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CO<sub>2</sub> MISCIBLE FLOODING APPLICATION AND SCREENING CRITERIA

by

MINGFEI YIN

A THESIS

Presented to the Faculty of the Graduate School of the  
MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

In Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE PETROLEUM ENGINEERING

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Approved by  
Dr. Mingzhen Wei, Advisor  
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Dr. Ralph Flori

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## ABSTRACT

Field experience has shown that CO<sub>2</sub> miscible flooding is an effective method to improve oil recovery, but only with proper reservoir candidate selection and optimal project design. This paper discusses both CO<sub>2</sub> miscible and immiscible flooding mechanisms and offers some guidelines for flooding operations. New developments in MMP determination are also introduced.

This research is based on a summary of field data from 134 CO<sub>2</sub> projects in the U.S. Several numerical methods have been applied for data cleaning. After cleaning, data from 128 projects have been analyzed and correlated. Carbonate reservoirs and sandstone reservoirs are the two main reservoir types for CO<sub>2</sub> flooding in the U.S. In order to develop customized screening criteria for each parameter, ranges for different reservoir types were analyzed respectively. In addition, the minimum miscibility pressure of CO<sub>2</sub> flooding was collected from literature to provide a better operation scope.

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## NOMENCLATURE

Symbol	Description
$E$	Oil displacement efficiency
$E_v$	Volumetric displacement efficiency
$E_d$	Macroscopic displacement efficiency
$E_i$	Vertical sweep efficiency
$E_s$	Areal sweep efficiency
$M$	Mobility ratio
$N_c$	Capillary number
$\mu$	Fluid viscosity, (Pa.)
$\sigma$	Interfacial tension (N/m)
$v$	Darcy velocity (m/s)
$\lambda_{ing}$	Mobility of displacing fluid
$\lambda_{ed}$	Mobility of displaced fluid
$P_c$	Pressure at critical point (psia)
$T_c$	Temperature at critical point (°F)
$V_c$	Velocity at critical point (cm <sup>3</sup> /mol)

## 1. INTRODUCTION

With the increasing need of oil and gas producing resources, recovery from existing mature hydrocarbon reservoirs has become a challenge. Many methods can be used to improve oil recovery among which, CO<sub>2</sub> miscible flooding is proved commercially successful in low permeable and light-oil reservoirs. CO<sub>2</sub> miscible displacement can increase recovery by 10%-20% (Moritis, 2004).

The utilization of carbon dioxide to increase oil recovery has several decades of history. It is carried out by injecting 30% or more of the hydrocarbon pore volume into the reservoir (Taber, 1997). When properly designed, it is proven to be one of the most promising EOR methods. The U.S. has the most CO<sub>2</sub> flooding projects around the world. One of the reasons for the increase in CO<sub>2</sub> injection is the cheap supply of CO<sub>2</sub> produced from natural CO<sub>2</sub> sources. CO<sub>2</sub> is as cheap as 1-2 U.S. dollar per Mscf (Manrique *et al*, 2010). With CO<sub>2</sub> source development and transportation pipeline system construction, CO<sub>2</sub> projects are economically attractive at oil prices around 20 US dollars per barrel (Manrique *et al*, 2007; Moritis, 2001). Since 1984, CO<sub>2</sub> miscible flooding projects took place in many reservoirs in the Permian Basin and Rangely Field.

With the development of more and more EOR methods, most reservoirs have multiple options. Besides oil and injection fluid prices, there are additional concerns when choosing an EOR method. Technical criteria are used to rule out the less-likely candidates. These screening criteria could to a large extent, influence the operation determination. If only reservoir depth and oil gravity are considered, about 80% of the world's reservoirs are qualified for some type of CO<sub>2</sub> injection (Taber, 1997). Normally, prior to the determination of CO<sub>2</sub> injection, some of the reservoir and fluid

characteristics should be considered. These characteristics include reservoir depth, temperature, net pay thickness, permeability, porosity, heterogeneity, crude oil viscosity and gravity, reservoir parting pressure, and reservoir oil saturation.

This research is conducted for the purpose of providing an insightful guidance on the selection of EOR methods. Based on a dataset generated from 1980-2014 CO<sub>2</sub> miscible flooding field applications, this study includes existing screening criteria and also provides a more accurate and customized criteria. Both graphical and statistical methods were utilized in the data analysis.

This thesis is organized into five sections. The first section states the overall objectives of the study. The second section is a literature review over the basic knowledge and current status of enhanced oil recovery methods. The third section is an introduction of the CO<sub>2</sub> flooding method. Mechanisms of CO<sub>2</sub> miscible and immiscible flooding are explained along with an important parameter known as the minimum miscibility pressure (MMP) and its determination are also discussed. The fourth section covers data collection and analysis. In this section, methods of data selecting and cleaning are provided. All parameters that influence the CO<sub>2</sub> miscible flooding are analyzed. Data distributions and ranges are displayed and summarized. The last section goes over the summary and conclusion.

## **2. LITERATURE REVIEW**

In order to have a better understanding of the CO<sub>2</sub> displacement process, a literature review based on background knowledge is provided. This literature review includes a basic EOR technology introduction, CO<sub>2</sub> properties, miscible and immiscible displacement mechanisms, MMP, and MMP determination methods. In addition, different CO<sub>2</sub> injection strategies such as WAG and surfactant foams are also discussed.

### **2.1. EOR INTRODUCTION**

Oil development and production can include up to three phases: primary recovery, second recovery, and tertiary also known as enhanced oil recovery. During the primary recovery process, oil is recovered by natural energy of a reservoir. The driving energy may be derived from rock and liquid expansion, water drive, the expansion of dissolved gas, gravity drainage, or the combination of these effects. This energy drives oil into the wellbore together with artificial lift. It reaches its limit either when the pressure in the reservoir is too low to produce, or when the proportion of gas or water in the produced fluid becomes too high.

In order to produce more oil, the pressure in the reservoir must be maintained by injecting other fluids. This period of production is called secondary recovery. The secondary recovery technique recovers oil in place generally by injecting water and/or gas. The injection of fluids has two main objectives: to maintain reservoir pressure, and to drive reservoir oil to the wellbore. After several years of secondary recovery, the injected fluid reaches the production well and make up a high proportion of the produced fluids. Secondary recovery reaches its limit when production is no longer cost effective.

Primary and secondary recovery together could recover about 1/3 of the original oil in place.

Enhanced oil recovery (EOR) is a process that refers to the displacement of the remaining oil in the reservoir. Particularly, EOR refers to oil recovery by the injection of materials not normally present in reservoir. There is another term “IOR” that needs to be distinguished from EOR. Generally, IOR (improved oil recovery) often refers to the oil recovery by any process. Oil production from EOR projects continues to supply an increasing percentage of the world oil production. About 3% of the worldwide oil production comes from EOR.

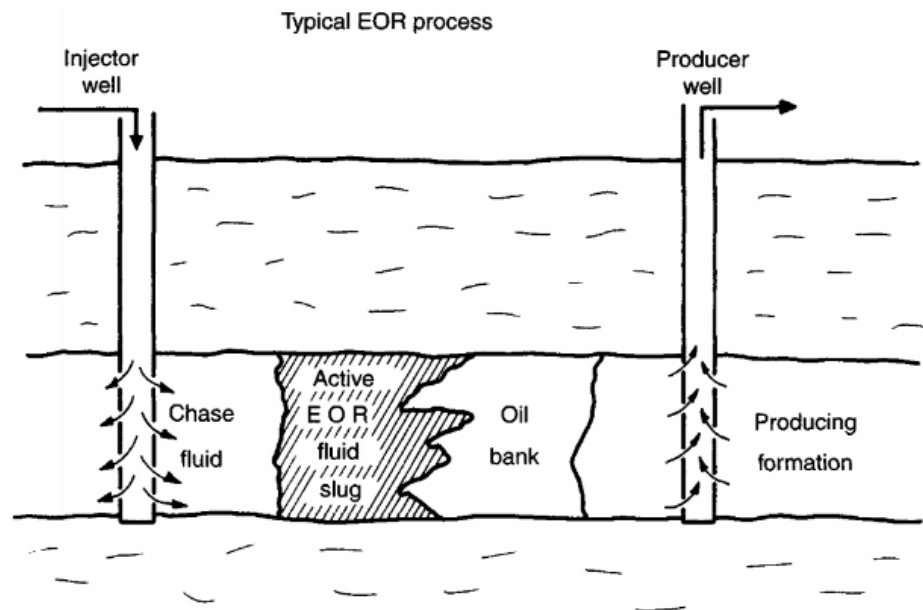


Figure 2.1. General schematic of enhanced oil recovery (Lyons & Plisga, 2005)



The injected fluids must improve the natural energy in the reservoir and interact with the reservoir rock or oil system to provide a favorable condition for residual oil recovery.

Effects that injected fluids have on the reservoir oil system include increasing capillary number and decreasing mobility ratio by:

- Reduction of interfacial tension between oil and displacing fluid
- Reduction of capillary forces
- Oil viscosity reduction
- Increase of drive water viscosity
- Reservoir rock wettability alteration

The ultimate goal of EOR processes is to increase overall oil displacement efficiency,  $E$  which is a combination of microscopic displacement efficiency,  $E_v$  and macroscopic or volumetric displacement efficiency,  $E_d$ :

$$E = E_v E_d \quad (1)$$

**2.1.1. Microscopic Displacement.** Microscopic efficiency refers to the displacement of oil at the pore scale. Microscopic displacement efficiency is affected by the following factors: interfacial tension force, surface tension force, wettability, capillary pressure, and relative permeability.

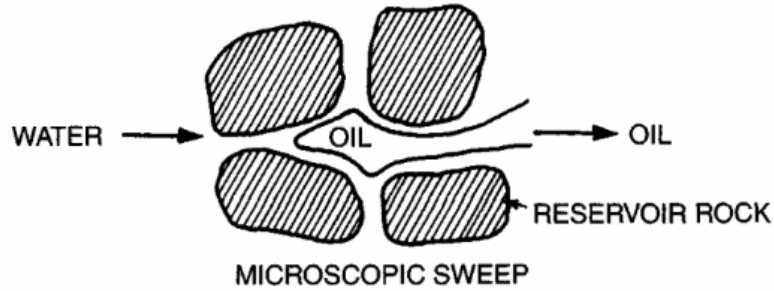


Figure 2.2. Schematic of microscopic displacement in pore scale (Lyons & Plisga, 2005)

Mobilization of residual oil is influenced by two major factors: capillary number ( $N_c$ ) and mobility ratio ( $M$ ).  $N_c$  is a dimensional group expressing the ratio of viscous to capillary forces. It is defined as  $N_c = \frac{\text{viscous forces}}{\text{capillary forces}} = \frac{v\mu}{\sigma}$ , where  $v$  is the Darcy velocity of displacing fluid (m/s),  $\mu$  is the displacing fluid viscosity (Pa.s), and  $\sigma$  is the interfacial tension between oil and displacing fluid (N/m).

Capillary numbers for mature waterflooding projects are commonly in the order of  $10^{-7}$  to  $10^{-6}$ . Capillary number can be increased by 3 orders of magnitude. In a miscible displacement, this value becomes infinite. At the microscopic scale, displacement efficiency could be increased by increasing the capillary number. According to the definition of capillary number, it can be increased by reducing interfacial tension or increasing the displacing fluid viscosity.

**2.1.2. Macroscopic Displacement.** The macroscopic displacement efficiency is a function of two terms, the areal ( $E_s$ ) and vertical ( $E_i$ ) sweep efficiencies:

$$E_v = E_s E_i \quad (2)$$

The other important factor is mobility ratio (M) and it is defined as  $M = \frac{\lambda_{ing}}{\lambda_{ed}} =$

$\frac{K_{ing} \mu_{ed}}{K_{ed} \mu_{ing}}$ , where  $\lambda_{ing}$  is the mobility of displacing fluid and  $\lambda_{ed}$  is the displaced fluid (oil).

Mobility influences the microscopic and macroscopic displacement efficiencies. A value of  $M \leq 1$  is favorable. Volumetric sweep efficiency increases as M decreases.

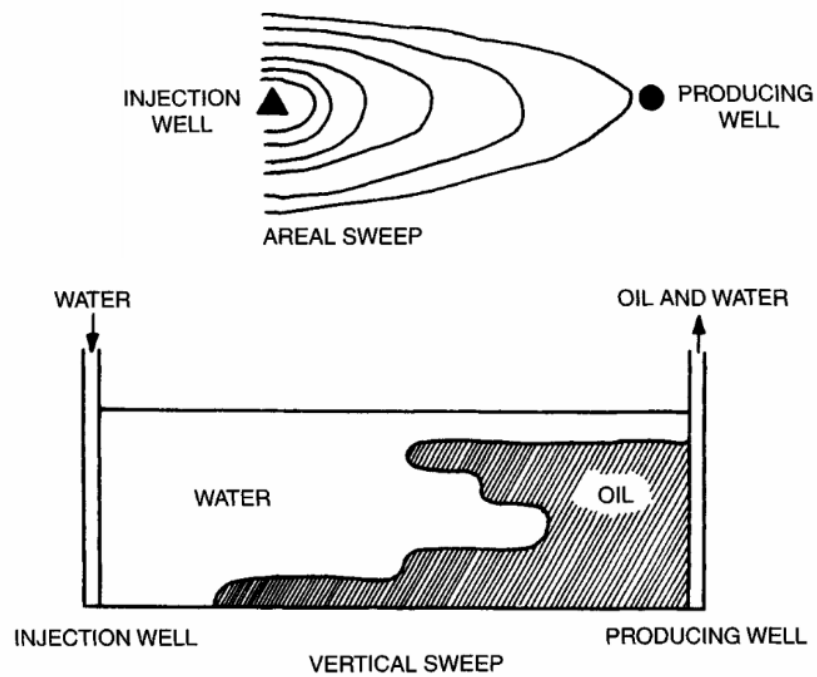


Figure 2.3. Areal and vertical sweep of macroscopic profile (Lyons & Plisga, 2005)

**2.1.3. Enhanced Oil Recovery Methods.** Many EOR methods have been developed for the recovery of light and heavy oil. They are generally classified into two main groups: thermal methods and non-thermal methods. Thermal methods are commonly applied on heavy oil while non-thermal methods are used for light oil.

**2.1.3.1 Thermal methods.** Thermal methods are the most advanced EOR methods and have been highly successful in the USA and Canada. The mechanisms include reduction in oil viscosity, rock and fluid expansion, compaction, and steam distillation. The most commonly used thermal methods are steam flooding, cyclic steam stimulation, and in-situ combustion.

For steam flooding, hot steam is injected into the formation and the reservoir oil is heated. Oil viscosity is reduced by the increase in temperature and mobility ratio. Besides the thermal expansion of crude oil, reduction of surface forces and steam distillation of the lighter portions of crude oil also contribute to the enhanced oil recovery. Steam flooding applications are limited to shallow and thin reservoirs.

The cyclic steam stimulation process is also known as “huff n’ puff” or steam soak. It is commonly used in heavy oil reservoirs at the beginning of EOR projects. Cyclic steam stimulation consists of three stages: first steam is continually injected into the wellbore, the well is then shut in for a period of time allowing the well to “soak” in the hot environment as heat distributes, and following that, the well resumes production. Cyclic steam stimulation has a relatively quick payout and that is the reason why it is used at the beginning of a thermal EOR project.

In-situ combustion is also called fire flooding. It is a process that involves igniting the crude oil downhole and then injecting gas containing oxygen into the wellbore where combustion is generated. The flame front then propagates through the reservoir. This process has a very high thermal efficiency and high viscosity reduction occurs near the combustion zone.

The main problems associated with thermal methods are the loss of heat, poor injectivity of steam or air, and poor sweep efficiencies. Sometimes high temperature environments will cause erosion problems.

**2.1.3.2 Non-thermal methods.** Non-thermal methods are best suited for light oil reservoirs. The two major categories under non-thermal methods are: gas miscible/immiscible flooding and chemical flooding. The main objectives in non-thermal methods are lowering the interfacial tension and improving the mobility ratio. Among all non-thermal methods, CO<sub>2</sub> flooding has been commercially successful in North America for decades. A few chemical methods are also notable, especially in China.

Gas miscible flooding implies that the displacing gas is miscible with reservoir oil either at first contact or after multiple contacts. A transition zone will develop between the reservoir oil and displacing gas. Mechanisms of miscible gas flooding include reduction of oil viscosity, the vaporization of oil, and the reduction of interfacial tension. Generally, gases used to conduct gas flooding are CH<sub>4</sub>, N<sub>2</sub>, and CO<sub>2</sub>. Among all gas flooding methods, CO<sub>2</sub> miscible flooding, is no doubt, the most successful and widely used method. When insufficient reservoir pressure is available or the reservoir oil composition is less favorable, the injected gas is immiscible with the reservoir oil. The main mechanisms involved in immiscible flooding are: oil viscosity reduction, oil phase swelling, the extraction of lighter components, and the fluid drive.

Chemical methods utilize a chemical reagent as the displacing fluid which promotes an increase in capillary number and a decrease in mobility ratio. Chemical recovery methods include polymer flooding, alkaline flooding, surfactant flooding, micellar flooding, and some conformance control treatment such as gel injection.

Polymer flooding is an important mature chemical treatment. The world's largest polymer field is the Daqing Oilfield in China. Polymer flooding accounts for improving sweep efficiency by increasing mobility ratio and decreasing viscosity contrast. HAPM, xanthan, and HASP/AP are the three main types of polymers that are utilized widely (Saleh, 2014).

The key outcome of surfactant flooding is the low interfacial tension effect. These mechanisms involve emulsification, oil entrainment, bubble entrapment, and wettability alteration. Alkali is always used as a “sacrifice agent” in surfactant flooding. Alkali can reduce the adsorption of surfactant on the grain surfaces and can make the surfactant more efficient. Thus, less surfactant needs to be injected. Furthermore, in some projects, surfactant is designed to be injected together with alkali and polymer, which is known as ASP flooding. ASP flooding aims to improve both the microscopic and macroscopic recovery efficiency.

Gel application is considered as the most effective type of conformance control method. Gel is formed by adding additives into cross-linker and polymer or monomer. Gel treatments act as blocking agents to reduce channeling through fractures or high permeable zones in the reservoir without significantly decreasing productivity and can improve the overall oil recovery. Gel can be classified into two different types: in-situ gel and preformed particle gel (PPG). The in-situ gel is formed after injection and has better injectivity, while preformed particle gel is formed before injection and has a stronger structure.

### 3. CO<sub>2</sub> FLOODING

#### 3.1. CO<sub>2</sub> PROPERTIES

The idea of utilizing CO<sub>2</sub> to improve the recovery of oil was proposed in the 1950s when Whorton and Brownscombe received a patent for an oil-recovery method with CO<sub>2</sub> and it has received considerable attention since then (Holm, 1987). A lot of laboratory and deskwork has been conducted and in the 1970s, widespread field testing took place.

Under ambient conditions, carbon dioxide is a colorless, odorless, inert, and noncombustible gas. Its properties under standard conditions (1.01MPa, 0 °C) are:

- Molecular weight 44.010 g/mol
- Specific gravity with respect to air 1.529
- Density 1.95 kg/m<sup>3</sup>
- Viscosity 0.0137 mPa/s

The phase behavior of pure CO<sub>2</sub> is shown on a P-T diagram below.

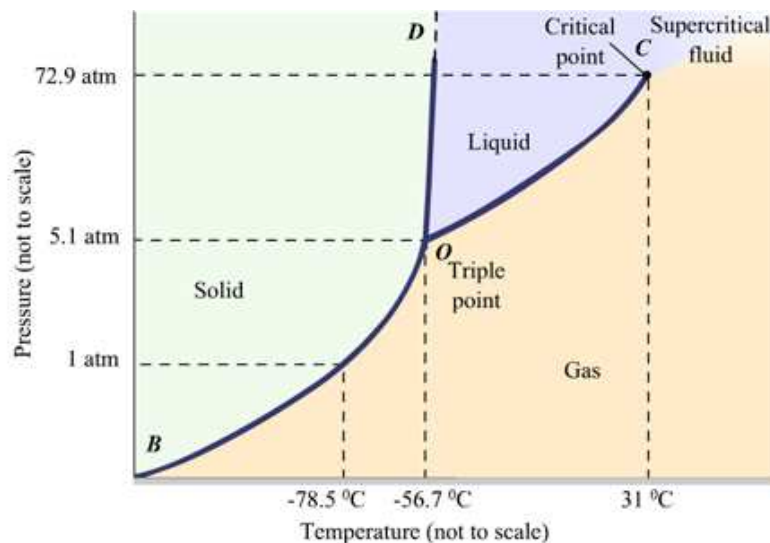


Figure 3.1. Carbon dioxide phase diagram (Chemistrybeta.com)

CO<sub>2</sub> is a solid at low temperature and pressures. Solid CO<sub>2</sub> will evaporate directly to gas at the temperature of -78.5 °C. As the temperature increases, the liquid phase appears for the first time and coexists with the solid and vapor phases at the triple point. With further increasing temperature and pressure, it reaches a critical point, where the CO<sub>2</sub> behaves as a vapor. Its critical properties are:

$$P_c = 7.39 \text{ MPa (1073 psia)}$$

$$T_c = 304 \text{ K (31.1}^\circ \text{ C, 37.8}^\circ \text{ F)}$$

$$V_c = 94 \text{ cm}^3/\text{mol}$$

Due to this critical temperature and pressure, CO<sub>2</sub> behaves as a supercritical fluid under most reservoir conditions (Klins, 1991).

At the critical conditions of pressure and temperature, the viscosity of CO<sub>2</sub> is 0.0335 cp which is higher than other probable injection gases (N<sub>2</sub>: 0.016 cp; CH<sub>4</sub>: 0.009 cp). CO<sub>2</sub> is (2 to 10 times) more soluble in oil than in the water. Dissolving in water, CO<sub>2</sub> increases the water viscosity and forms carbonate acid, which has a beneficial effect on shale and carbonate rocks.

### **3.2. CO<sub>2</sub> DISSOLUTION IN OIL**

The dissolution of CO<sub>2</sub> in crude oil results in the main factors that contribute to enhanced oil recovery.

The solubility of CO<sub>2</sub> in oil depends on the pressure, temperature and characteristics of the oil as was shown in Figure 3.2 below. ADA crude oil has a gravity of 30.3 °API while West Texas crude is of 39 °API. According to Figure 3.2, CO<sub>2</sub> has a higher solubility in lighter oil; this value is slightly greater when the temperature is



increased. When the pressure increases, solubility will increase and is sometimes limited to a saturation value.

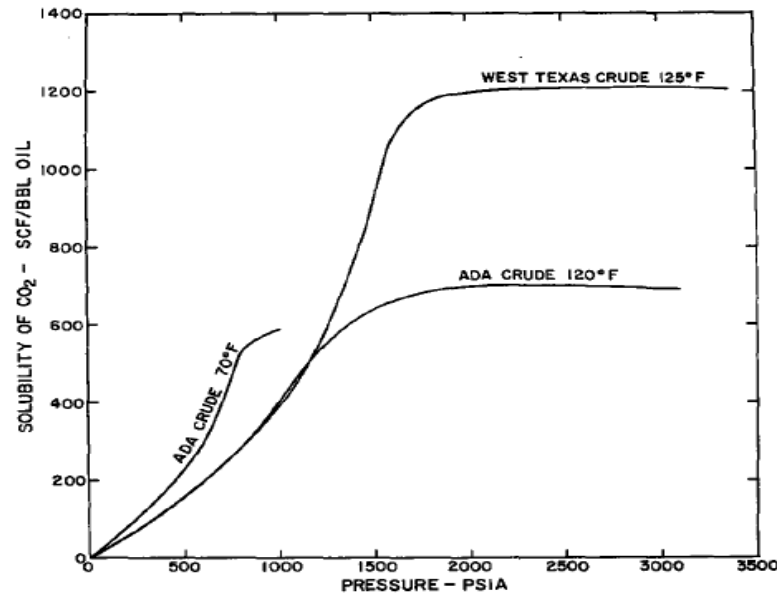


Figure 3.2. CO<sub>2</sub> solubility in crude oil (Crawford *et al*, 1963)

**3.2.1. Oil Swelling.** As a result of CO<sub>2</sub> dissolution into the crude oil, the oil volume will increase from 10 to 60%. This phenomenon is greater for light oil and leads to lower residual oil saturation (Holm, 1987).

Oil swelling increases the recovery factor for a given residual oil saturation increases, the mass of the oil remaining in the reservoir under standard conditions is lower than residual oil that has not had contact with the CO<sub>2</sub>.

**3.2.2. Viscosity Reduction.** CO<sub>2</sub> dissolution in crude oil also results in oil viscosity reduction. Calculations indicated that this viscosity reduction is the major mechanism for EOR.

Laboratory experiments show that, for any given saturation pressure, the viscosity reduction is relatively greater for oil with higher original viscosity (Klins and Bardon, 1991).

### **3.3. MISCIBLE DISPLACEMENT**

The miscible state is described by L.W. Holm as “the ability of two or more substances to form a single homogeneous phase when mixing in all proportions. For petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface. If two fluid phases form after some amount of one fluid is added to others, the fluids are considered immiscible.”

There are two processes involved in a miscible gas drive. The two processes are they are identified as the first contact miscibility process and the multiple contact miscibility process.

First contact miscibility is achieved when both fluids are completely miscible in all proportions without any multiple behaviors.

Other solvents are not directly miscible with reservoir oil, but miscibility can be achieved under certain conditions by in-situ mass transfer between oil and solvent through repeated contacts. This kind of miscibility is called multiple contact or dynamic miscibility. When large amounts of CO<sub>2</sub> are mixed with oil, intense mass transfer between phases occurs. Multiple contact miscibility is subdivided into two processes: condensing gas drive and vaporizing gas drive.

Both condensing drive and vaporizing drive are based on component transfer.

Components in the injected gas and reservoir oil can be classified into four groups:

- Lean components:  $\text{CO}_2$ ,  $\text{N}_2$ , and  $\text{CH}_4$  injection gas
- Light components:  $\text{C}_1$  (methane)
- Intermediate components:  $\text{C}_2$ - $\text{C}_6$ , these components are present in oil but not significantly present in the injection gas
- Heavy components:  $\text{C}_{7+}$  (heptane and heavier fractions)

**3.3.1. Vaporizing Gas Drive.** The most important function of  $\text{CO}_2$  is that it can extract or vaporize hydrocarbons from crude oil. Vaporizing gas drive mechanism refers to a process where a lean injection gas passes over reservoir oil rich in intermediate components and extracts those fractions from the oil and concentrates at the displacement front where miscibility is achieved. A schematic of  $\text{CO}_2$  gas vaporizing and condensing gas drive mechanisms are shown in Figure 3.3 below.

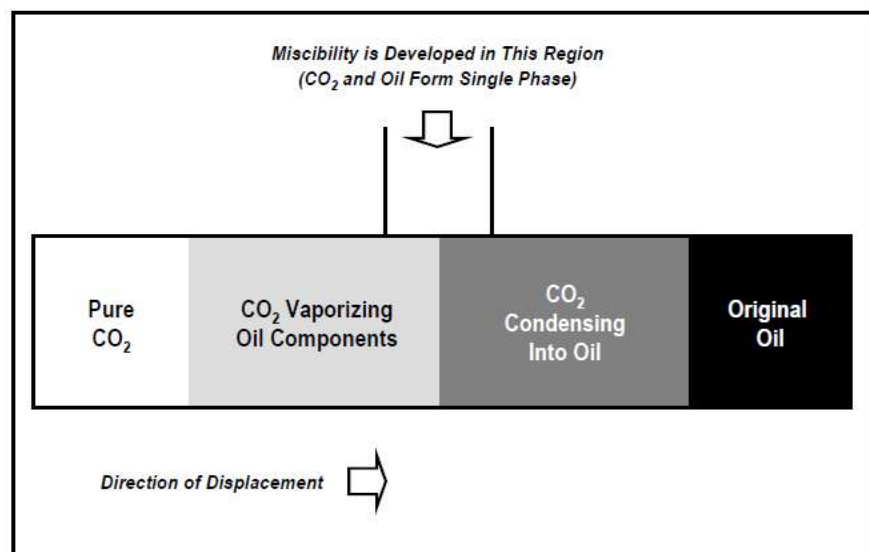


Figure 3.3. One dimensional schematic of  $\text{CO}_2$  miscible process (Advanced Resources International, Inc, 2005)

**3.3.2. Condensing Gas Drive.** Condensing is a process that refers to the transfer through condensation of intermediate components from rich solvent to intermediate-lean reservoir oil through condensation. In CO<sub>2</sub> miscible flooding, the intermediates that were stripped from the oil that are present in the gas condense when the gas encounters fresh oil downstream.

### **3.4. NEAR MISCIBLE DISPLACEMENT**

When the miscibility pressure cannot be reached or failed to be maintained due to either technical or economic factors, CO<sub>2</sub> injection is evaluated as near miscible or partial miscible. It is a process between immiscible and miscible displacement. The likely mechanisms of recovery include oil swelling, viscosity reduction, and light component extraction.

Normally, in such near miscible displacement cases, the ultimate oil recovery is less than the ones under miscible conditions. But on the up side, the amount of CO<sub>2</sub> required to produce additional oil is less, making the economics of the process attractive (Klins and Bardon, 1991).

### **3.5. IMMISCIBLE DISPLACEMENT**

When insufficient reservoir pressure is available or the reservoir oil composition is not favorable, injected CO<sub>2</sub> is immiscible with reservoir oil. Even if miscibility cannot be reached, a high recovery rate still can be achieved mainly due to:

- Oil swelling as it becomes saturated with CO<sub>2</sub>
- Viscosity reduction of the swollen oil and CO<sub>2</sub> mixture
- Solution gas drive

The first two mechanisms are the same as the miscible displacement process. The swelling of oil as CO<sub>2</sub> goes into solution was shown to contribute to the release of trapped residual oil, especially high gravity oil. Field applications of the immiscible CO<sub>2</sub> process, however, have been in low-gravity, high-viscosity crude oil reservoirs where the viscosity-reduction effect dominates (Holm, 1987).

Another CO<sub>2</sub> immiscible displacement mechanism recognized as solution gas drive. Like a primary produced reservoir, after the CO<sub>2</sub> injection process ends and the formation pressure decreases below the pseudo-bubble point pressure, gas comes out of the solution and forms a continuous gas phase. This contributes to the oil production by providing drive energy in the form of a solution gas drive mechanism.

### **3.6. MINIMUM MISCIBILITY PRESSURE**

The minimum miscibility pressure (MMP) is the minimum pressure at which injection gas and reservoir oil can mix and become one phase. Above MMP, the interfacial tension between reservoir oil and injected gas disappears. Therefore, MMP is a significant parameter for screening and selecting CO<sub>2</sub> miscible flooding candidates. Typically, CO<sub>2</sub> MMP is greater than 1,400 psia and changes under the influence of several factors.

**3.6.1. Factors Influencing MMP.** Minimum miscibility pressure (MMP) is a function of temperature and oil composition. Impurities in the injected CO<sub>2</sub> also have an impact on MMP.

**3.6.1.1 Reservoir temperature.** CO<sub>2</sub> MMP is temperature dependent which means reservoir temperature has a significant effect on CO<sub>2</sub> MMP determination for a

given reservoir oil. Usually, MMP increases as temperature increases. A simple temperature versus bubble point pressure of CO<sub>2</sub> MMP is shown below.

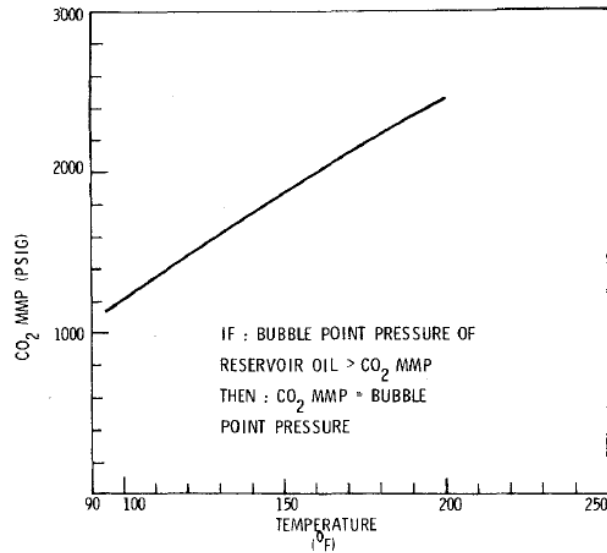


Figure 3.4. Temperature /bubblepoint pressure of CO<sub>2</sub> MMP correlation (Yellig and Metcalfe, 1980)

**3.6.1.2 Oil characteristics.** MMP between CO<sub>2</sub> and oil increases when volatile components in oil such as C<sub>1</sub> have a higher fraction. Intermediate components such as C<sub>2</sub> - C<sub>4</sub> in the reservoir fluid decrease the MMP. Moreover, higher molecular weight components such as C<sub>5+</sub> or C<sub>7+</sub> fraction in the reservoir oil result in a higher MMP (Alston *et al*, 1985).

**3.6.1.3 Injected CO<sub>2</sub> purity.** Pure CO<sub>2</sub> is not always available as an injection gas in the industry. Sources such as natural CO<sub>2</sub> reservoirs and process plant waste streams always contain impurities. Another potential impure CO<sub>2</sub> source is the produced gas

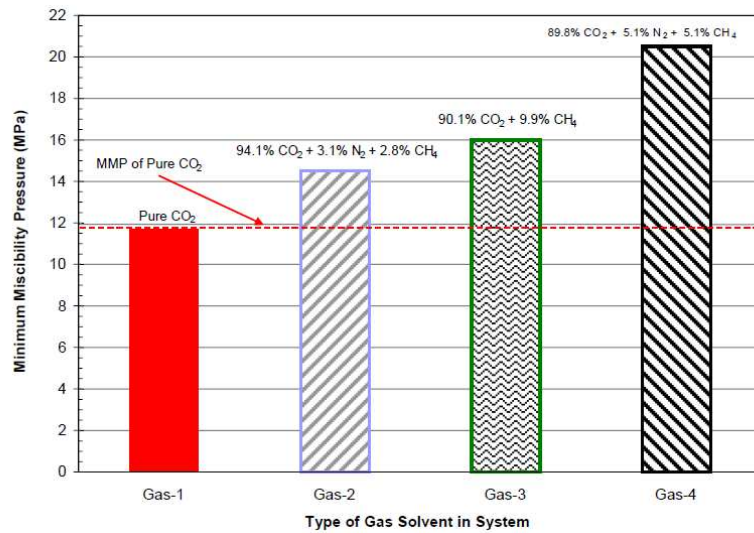
from wells under CO<sub>2</sub> flooding. Because high purity cleanup of the cycled gas is costly, produced gas is always re-injected to reduce costs.

Typically, impure CO<sub>2</sub> contains significant amounts of nitrogen, H<sub>2</sub>S, and hydrocarbons. Produced gas contains a wide variety of components from methane (CH<sub>4</sub>), nitrogen, H<sub>2</sub>S, and intermediate hydrocarbons (C<sub>2</sub> - C<sub>4</sub>). The presence of these impurities can affect the pressure required to achieve miscible displacement.

Many researchers studied the effect of impurities on MMP and provided different correlations. Yellig and Metcalfe (1980) conducted a series of slim tube experiments to measure this effect. Experimental results showed that CO<sub>2</sub> contaminated by C<sub>1</sub> or N<sub>2</sub> has an adverse effect on MMP. Conversely, the addition of C<sub>2</sub> - C<sub>4</sub> and H<sub>2</sub>S has shown to have the effect of decreasing the MMP. Zhang *et al* conducted MMP experiments using the rising bubble apparatus (RBA) with light oil mixed with pure or impure CO<sub>2</sub>. Results showed that when CO<sub>2</sub> contaminated with 10% CH<sub>4</sub> and/or N<sub>2</sub>, MMP could increase as much as 70% (Zhang *et al*, 2004). CO<sub>2</sub> containing 37% C<sub>3</sub>H<sub>8</sub> could reduce the pure CO<sub>2</sub> MMP by 45%. Effects of different contaminants on MMP are shown in the following figures. Gas compositions are listed in Table 3.1 below:

Table 3.1. Gas compositions in impurity MMP experiment (Zhang *et al*, 2004)

Gas name	Composition
Gas 1	Pure CO <sub>2</sub>
Gas 2	94.1%CO <sub>2</sub> + 3.1%N <sub>2</sub> + 2.8% CH <sub>4</sub>
Gas 3	90.1%CO <sub>2</sub> + 9.9% CH <sub>4</sub>
Gas 4	89.8%CO <sub>2</sub> + 5.1%N <sub>2</sub> + 5.1% CH <sub>4</sub>
Gas 5	70%CO <sub>2</sub> + 30% H <sub>2</sub> S
Gas 6	70%CO <sub>2</sub> + 30% SO <sub>2</sub>
Gas 7	85%CO <sub>2</sub> + 15% N <sub>2</sub>
Gas 8	65%CO <sub>2</sub> + 15%N <sub>2</sub> + 20% SO <sub>2</sub>
Gas 9	80%CO <sub>2</sub> + 5%N <sub>2</sub> +5%O <sub>2</sub> + 10% SO <sub>2</sub>

Figure 3.5. Effect of contaminated CO<sub>2</sub> on MMP for steelman stock tank oil (Zhang *et al*, 2004)



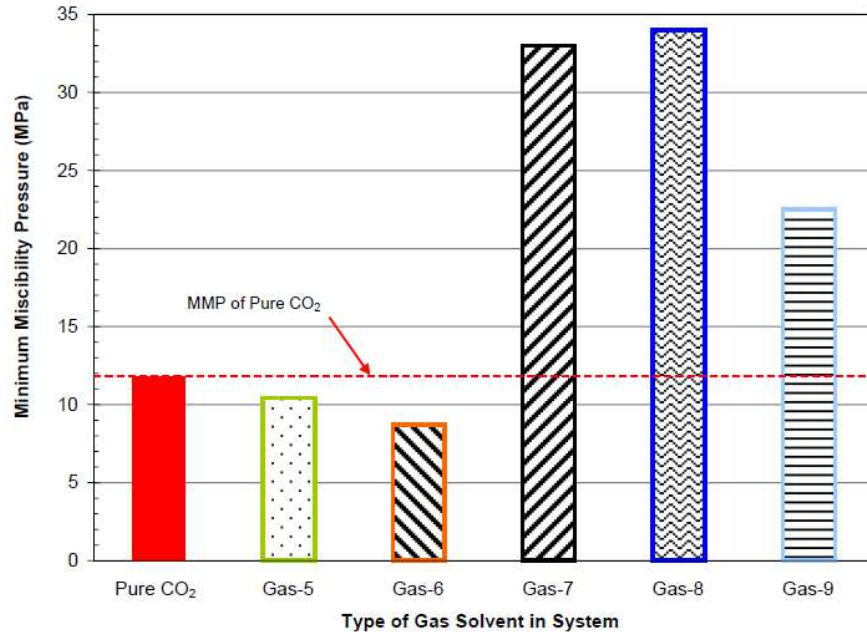


Figure 3.6. Effect of contaminated CO<sub>2</sub> on MMP for steelman stock tank oil (Zhang *et al*, 2004)

### 3.7. MMP DETERMINATION

In order to provide a precise MMP, different measurements have been proposed in literature.

Slim tube methods are traditionally used to estimate MMPs because they model the interaction of flow in porous media and phase behavior of crude oil. Besides slim tube methods, multi-contact mixing cell experiments can measure more accurate MMP for vaporizing or condensing gas floods. Computational methods for MMP estimation have been developed over the years based on equation of state (EOS). There are three main methods: analytical calculation using methods of characteristics, multiple cell models, and 1-D slim tube simulation.

**3.7.1. Experimental Methods.** Experimental methods include the slim tube method, and the rising bubble apparatus (RBA).

**3.7.1.1 Slimtube method.** The slim tube method was first proposed by Yellig and Metcalfe in 1980 (Yellig and Metcalfe, 1980). There was no standard method available in literature at that time for determining CO<sub>2</sub> MMP. The slim tube method is the first satisfactory way. Over the years, slim tube method has been the most widely used laboratory technique to determine MMP for miscible injection projects.

The slim tube experiments are conducted in a long stainless steel tube and packed with certain particle-sized sand, saturated with reservoir oil at the desired test temperature and pressure. Typical diameter of the tube is 1/4 in while length ranges from 6 to 20 meters. Small tube diameter and long tube length, are designed to avoid effects of CO<sub>2</sub> fingering, transition zone length and transverse compositional variations. The coil is placed horizontally or with a very low dip angle, to reduce gravity impacts on displacement. The CO<sub>2</sub> supply cylinder is filled with 90% pure CO<sub>2</sub> which is injected into the coil at a certain rate. A schematic of a slim tube apparatus is shown in Figure 3.7 below.

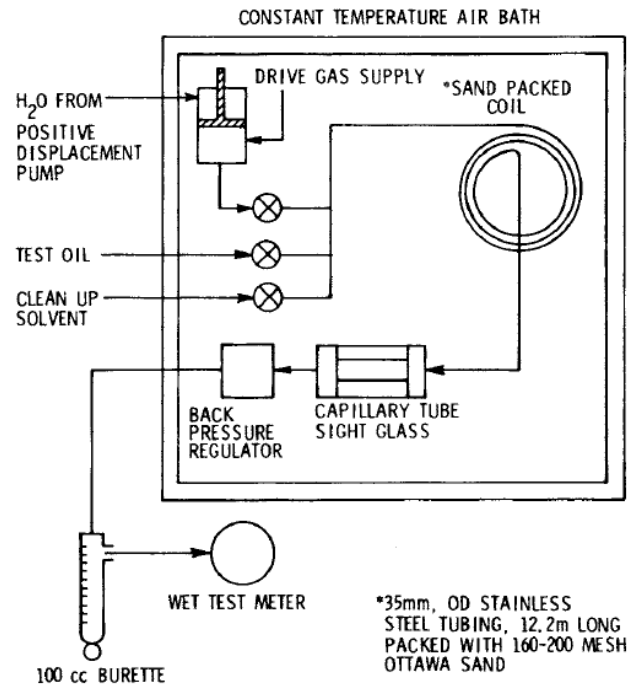


Figure 3.7. Schematic of slim tube experiment apparatus (Yellig and Metcalfe, 1980)

With the increasing level of pressure, recovery first increases, then becomes stabilized. Recovery versus pressure is plotted after 1.2 pore volume of  $\text{CO}_2$  is injected. A typical recovery curve is given below.

The breakpoint of this curve indicates displacement from immiscible to miscible. Pressure at this point is the minimum miscibility pressure.

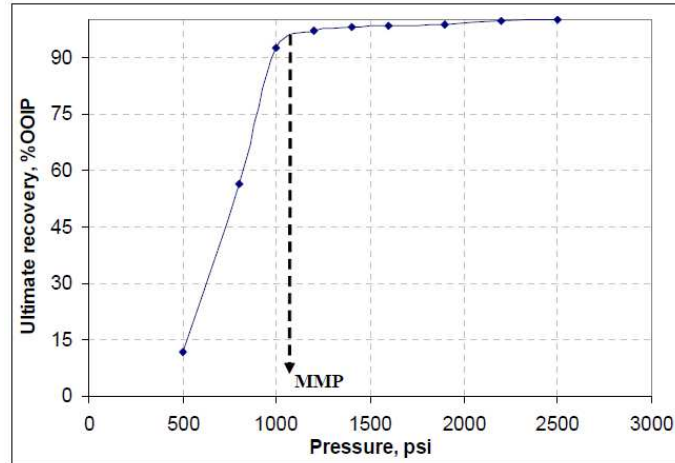


Figure 3.8. Schematic of slim tube recovery plot and its corresponding MMP value (Yousef *et al*, 2008)

However, the length of coil, CO<sub>2</sub> injection rate, coil diameter, as well as the type and size of the packing material varies in different literature. Orr et al (1982) pointed out that there is no unified experimental procedure or criteria defining MMP. Some of the different experiment procedures in published literature for MMP determination are summarized in the Table 3.2 below.

Table 3.2. Different slim tube experiment apparatus comparison (Flock and Nouar, 1984)

Experimenter	Displacement	Apparatus Parameters	MMP Criteria
Deffrene <i>et al</i> (1961)	Vertical	Tube length: 1.5m Tube diameter: 0.01m Packing material: 60-65 mesh glass beads	Plot of recovery v.s. pressure at gas breakthrough or after 1 PV injection should show a clear break in slope for a value of $P = \text{MMP}$
Yellig and Metcalfe (1980)	Horizontal	Tube length: 12.2m Tube diameter: 6.3mm Packing material: 160-200 mesh sand	Oil recovery of 90% when 1.2 PV of gas injected
Elsharkawy <i>et al</i> (1992)	Horizontal	Tube length: 18.3m Tube diameter: 3.05mm Packing material: 100 mesh sand	Break-over pressure in the plots; or at 1PV to 1.2PV of injected gas or ultimate oil recovery against displacement pressure.
Ekundayo <i>et al</i> (2013)	Horizontal	Tube length: 12.2m; 18.3m; 24.4m Tube diameter: 3.05mm; 4.57mm Packing material: 80-120 mesh Ottawa sand	1.2 or 1.4 PV of gas had been injected or when the produced GOR is greater than 100,000SCF/STB
Holm and Josendal (1974)	Horizontal	Tube length: 14.6-25.6 m Tube diameter: $0.472 \times 10^{-2} \text{m}$	Define miscible displacements as those that recover more than 80% of the IOIP at gas breakthrough, and that more than 94% of IOIP is recovered ultimately.

In order to standardize experiment procedures, many researchers have discussed how different experiment designs affect MMP measurement. Flock and Nouar (1984) studied effects of tube length and injection rate on displacement efficiency and discussed

their effects on the criteria used for MMP estimation (Flock and Nouar, 1984). Based on their experiments, they concluded that MMP measurement depended to a great extent on the length of the slim tube and to a lesser extent on injection rate when the slim tube is long enough. The authors also concluded that a longer slim tube may result in lesser gravity and viscous fingering effects. According to the authors, a minimum requirement of coil length for a good MMP estimation is 12.2m. The authors also recommended that slim tube inner diameter should be small to minimize gravity and fingering effects.

Ekundayo *et al* (2013) also discussed how coil length and diameter as well as injection rate influence MMP measurements. They ran 30 sets of experiments using the same oil sample and injection gas under different injection rates in two kinds of coils. 26 of the experiments were conducted in a coil with a diameter of 3.05mm having lengths of 12.2m, 18.3m and 24.4m. The other four experiments were conducted in a coil with a diameter of 4.57mm and a length of 18.3m. The authors concluded that there is no certain relationship between MMP and injection rate. High injection rate may cause deviation because true miscibility was not achieved since the gas did not have enough time to interact with the oil. Moreover, when the coil length is increased, there is a decreasing trend of MMP. MMP was also found to be lower when using a larger diameter coil, while oil recoveries were found to be higher with a smaller coil.

It should be pointed out that even though the slimtube method is considered as the standard way to measure MMP, its drawbacks are that it is time consuming and expensive. It may take weeks to conduct one set of injection. Furthermore, MMP estimates may not be accurate because of dispersion and the lack of data points (Johns *et al*, 2002).

**3.7.1.2 Rising bubble technique.** The rising bubble apparatus was designed as a reliable and fast alternative to a slim tube measurement. It was first proposed by Christiansen and Haines in 1987 (Christiansen and Haines, 1987). Unlike the slimtube measurement, MMP determination is not based on oil recovery and its corresponding pressure. Rising bubble measurement is based on a direct visual observation.

Rising bubble apparatus consists of a flat glass tube installed vertically in a high-pressure sight gauge. The whole apparatus is placed in a temperature-controlled bath. The tube is flat with a vertical incident light so that gas bubbles are visible even in opaque crude oil. The visible portion of the tube is about 20cm long and the internal cross sectional area of the glass tube is 1x5mm. Gas bubbles are injected into the glass tube from a hollow needle at the bottom of the sight gauge. A schematic of a rising bubble experiment apparatus is shown in Figure 3.9.

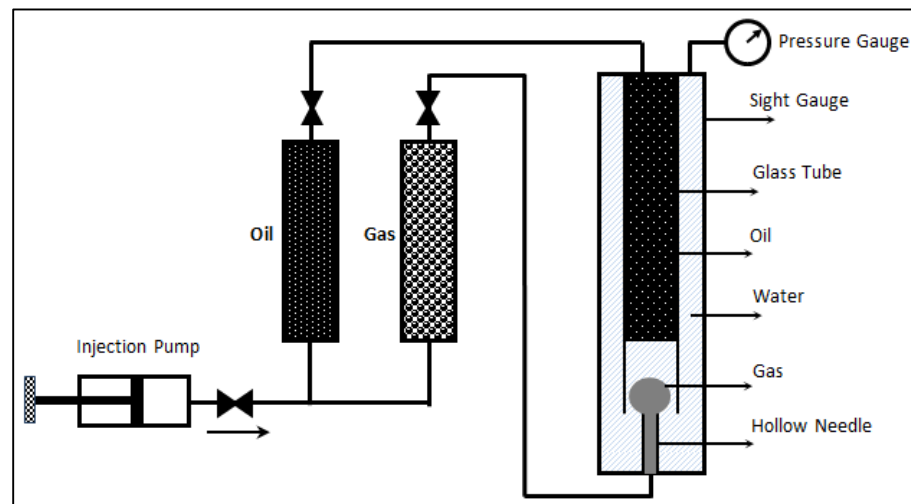


Figure 3.9. A schematic of rising bubble apparatus. (Perminc.com)

As shown in the figure, the sight gauge and glass tube are initially filled with distilled water. Then, oil is injected into the glass from the top of the tube to displace the

water. The bottom portion of the glass tube is still filled with water while the remainder of tube is filled with oil. A small bubble of gas is injected into the tube from the bottom and then, rises through the whole water/oil column. After two or three gas bubbles have been injected through the oil, the oil is replaced with fresh oil. The whole rising process of the bubble and its shape and behavior are observed and photographed with a camera. The forms of the bubble when the pressures are below and above MMP are shown in Figure 3.10.

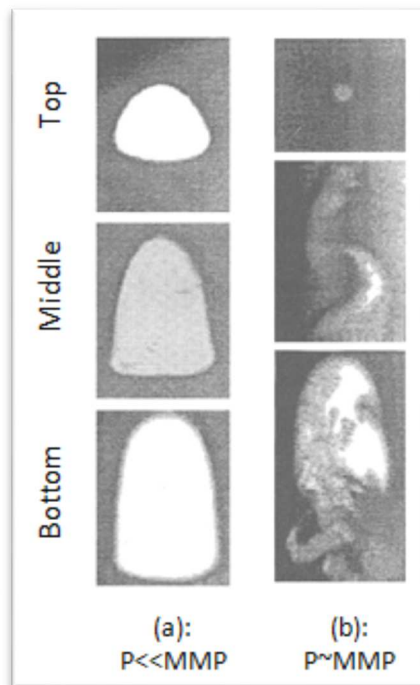


Figure 3.10. Bubble forms with pressure. (Perminc.com)

The author divided bubble behavior into three types according to pressures. Type A is below the MMP: the bubble will remain in its initial shape while rising through the



column of oil, however the size of the bubble will shrink. Type B is at or slightly above MMP: the gas/oil interface will vanish from the bottom of bubble and then the contents of it rapidly disperse in the oil. This is a multiple contact miscibility process. Type C is above the MMP: the bubble will disperse faster than type B. This is a first contact miscibility.

Unlike the slim tube method, it takes between 5 to 30 seconds for a bubble to rise through the oil column with a RBA. The whole MMP measurement experiment takes about 1-2 hours versus weeks using the slimtube method.

**3.7.2. Numerical Methods.** An experimental method such as the slimtube estimation is subjected to the impact of experimental parameters and multiphase flow parameters such as relative permeability. The rising bubble and slim tube do not completely model multi-contact mechanisms between gas and oil. Because of the drawbacks of experiments, computational methods have been developed over the years.

**3.7.2.1 Multiple cell model.** The multiple cell model concept is based on running a series of repeated forward and reverse contact experiments, resulting in new initial oil and initial gas compositions. As was described in the previous section, miscible displacement consists of condensing and vaporizing gas drives. Miscibility in vaporizing gas drives is developed at the leading edge of the displacement while for condensing drives, it is developed at the trailing edge of the development. For pure condensing or vaporizing gas drive, the multiple cell model can provide robust and reliable estimations. However, for combined CV drives which most displacements are, multiple cell model methods are not considered convincing.

**3.7.2.2 1-D slim tube simulation.** One dimensional slimtube simulation is a favorable alternative to the slim tube experiment as the latter is expensive and time consuming. The simulation utilizes well-characterized EOS fluid models to mimic the flow in porous media. It is based on compositional simulation of solvent injection into one dimensional porous media under miscible conditions. A prerequisite for the simulation is that the numerical and physical diffusion of the fluid have to match.

### **3.7.3. Analytical Model.**

**3.7.3.1 Empirical correlations.** Empirical correlations predict CO<sub>2</sub> MMP as a function of three variables: mole fractions of light components in the reservoir oil, molecular weight of a plus fraction, and temperature. Holm and Josendal (1974) proposed the first MMP correlation based on reservoir temperature and molecular weight of C<sub>5+</sub> components in reservoir oil. A correlation was provided by the National Petroleum Council (NPC) in 1976, predicting MMP according to temperature and oil gravity. Yelling and Metcalfe (1980) simplified the correlation so that MMP could be predicted based on reservoir temperature. Alston *et al* (1985) proposed a correlation with temperature, oil composition, and an averaged weight critical temperature for impure CO<sub>2</sub>. Factors such as extrapolated vapor pressure of CO<sub>2</sub> were considered by some other researchers.

**3.7.3.2 Method of characteristics.** Method of characteristics (MOC) aims to solve the problem of multi-component fluid flow in porous media. This method enables the construction of an analytical solution describing the composition path from initial gas composition to the initial oil composition. MOC is associated to key tie-line approach. Earliest attempts to calculate MMPs referring to key lines were ternary theory for multi-

contact miscible displacement. MMP is defined as the pressure at which the critical tie line passes exactly through the gas representative point.

Wang and Orr (1997) developed a four-composition system as shown in the figure below. Three key types of tie-lines control miscibility in a multi-component system. MMP is determined as the lowest pressure when the length of one of the key tie-lines becomes 0.

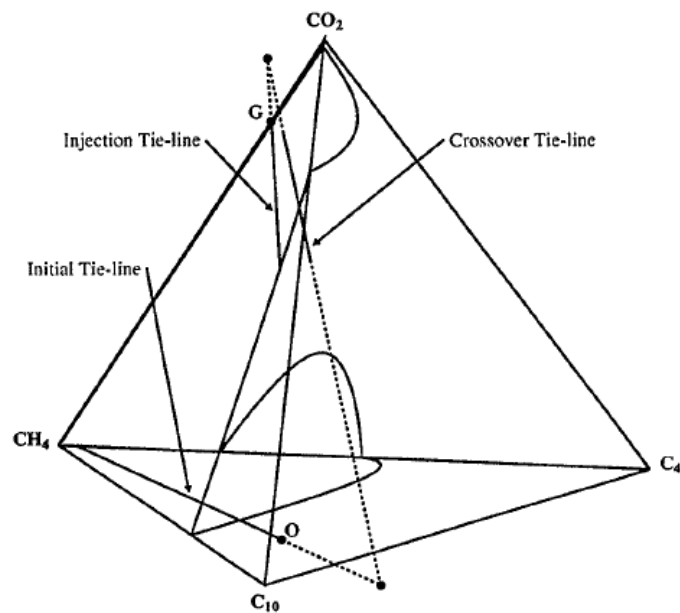


Figure 3.11. Key tie-lines intersect each other for a displacement of oil O by gas G  
(Wang and Orr, 1997)

### 3.8. $\text{CO}_2$ FLOODING PROBLEMS

Gas injection has many advantages over water flooding especially in tight reservoirs. Low permeability and porosity will decrease injectivity and feasibility for water flooding. However, there are some problems associated with gas injection.

**3.8.1. CO<sub>2</sub> Conformance Control Problems.** One of the major problems associated with CO<sub>2</sub> flooding in particular is its low viscosity, resulting in unfavorable mobility difference between CO<sub>2</sub> and oil.

With high mobility, CO<sub>2</sub> bypasses most of the crude oil in the flood pattern and, seeks the path of least resistance through the largest throats or pores and takes the most direct route between the injection well and the production well. Sometimes, due to reservoir heterogeneity, CO<sub>2</sub> goes through high permeable layers and fractures. As a result, much of the oil is not contacted and left unswept. Indications of poor sweep efficiency is seen by early CO<sub>2</sub> breakthrough. These disadvantages are known as fingering and channeling problems. In addition, a gravity overriding problem is unfavorable due to the low gravity of CO<sub>2</sub>.

**3.8.2. Asphaltene Deposition and Scale.** When mixed with crude oil, CO<sub>2</sub> has significant potential for flocculating the asphaltene molecules in the oil. This phenomenon may happen in the near injection well bore area where CO<sub>2</sub> content of the mixture is as high as 60-70% (Honarpour *et al*, 2010).

Normally, when oil is stabilized by resins and intermediate hydrocarbon components, asphaltene exists as a dispersed phase within the oil. During the vaporizing drives, as CO<sub>2</sub> extracts intermediate components from oil, it leads to instability. As a result, asphaltene will flocculate and eventually precipitate. Asphaltene may cause near wellbore pore throats to plug and thus affect permeability and even CO<sub>2</sub> injectivity.

**3.8.3. Formation Dissolution.** As an acid gas when dissolved in water,  $\text{CO}_2$  forms a weak acid which in turn can react with the formation, especially in carbonates. The reaction between  $\text{CO}_2$ -formed acid and the formation can cause rock dissolution and changes to the reservoir heterogeneity.

## 4. DATA COLLECTION AND ANALYSIS

### 4.1. DATA PREPARATION

This research is based on collected data from CO<sub>2</sub> flooding applications that have been published in reports from 1996 to 2014. Projects include continuous CO<sub>2</sub> injection, WAG injection, and SAG injection. Data preparation consisted of three steps: data collecting, data cleaning, and numerical analysis.

**4.1.1. Data Collection.** A dataset was set up based on data collected from 134 CO<sub>2</sub> projects in the U.S from The Worldwide EOR Survey 1996 to 2014 published in the *Oil and Gas Journal*. Reservoir characteristics, production, injection strategies, and MMP are collected and examined. Although CO<sub>2</sub> projects are conducted widely around the world, but about 93% of the CO<sub>2</sub> projects are located in the U.S. For an accurate comparison, only data collected from U.S. projects are analyzed. Outside the U.S., CO<sub>2</sub> floods have been implemented in Canada, Hungary, Turkey, and Trinidad.

Within the U.S., CO<sub>2</sub> floods are mainly implemented in the Permian Basin in Texas, as well as in Louisiana, Mississippi, Wyoming, Oklahoma, Colorado, New Mexico, Michigan, Utah, and Kansas. The most productive areas are the Permian Basin, Rangely Field, Salt Creek Field, and Bighorn Basin. The highlighted areas in the map shown in Figure 4.1 indicate the locations of CO<sub>2</sub> projects.

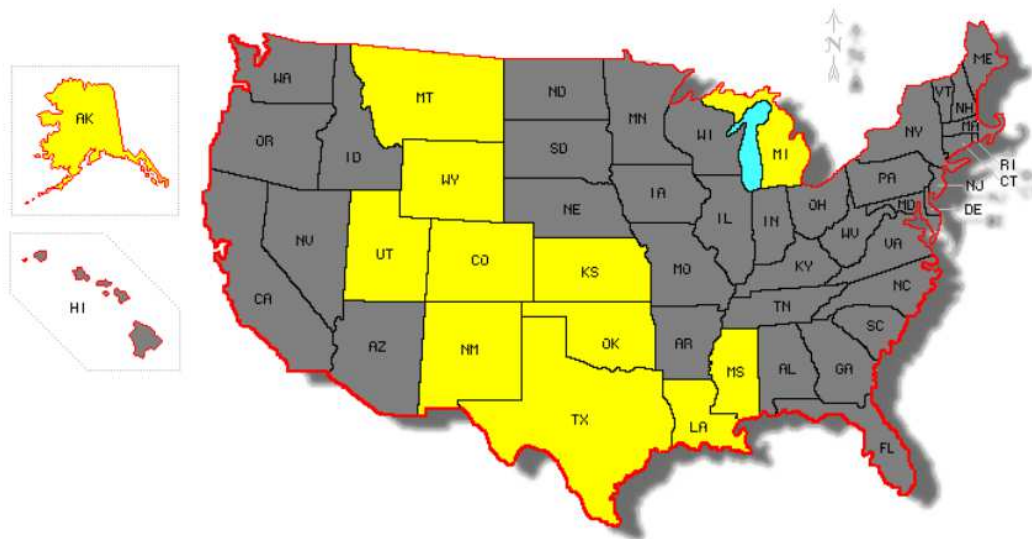


Figure 4.1. States that CO<sub>2</sub> projects have been conducted.

In the year 2014, as many as 22 companies implemented CO<sub>2</sub> flooding. 128 projects contributed about 126 million tons of oil (Leena, 2014). The main operators and their productions are listed below.

Table 4.1. Main CO<sub>2</sub> miscible flooding operators and production (Leena, 2014)

Operator	Number of Projects	Enhanced Production (1*10 <sup>4</sup> tons)	Percentage (%)
Occidental	33	459.63	36.37
Kinder Morgan	3	138.34	10.94
Chevron	7	126.30	9.99
Hess	4	106.89	8.46
Denbury Resources	18	86.82	6.87
Merit Energy	7	71.12	5.63
Anadarko	6	55.79	4.41
ExxonMobil	1	45.36	3.59
Breitbart Energy	5	36.87	2.92
ConocoPhillips	2	28.42	2.25
Whiting Petroleum	1	24.51	1.94
Apache	5	23.88	1.89
XTO Energy Inc.	4	13.43	1.06
Chaparral Energy	8	9.18	0.73
Fasken	5	4.30	0.34
Core Energy	9	1.90	0.15
Other	12	31.19	2.47

Considered as the most promising EOR method in the U.S., the number of CO<sub>2</sub> flooding projects has continued to increase since the 1980s. CO<sub>2</sub> flooding (miscible and immiscible) and thermal methods contribute most of the EOR production. The growing number of CO<sub>2</sub> projects is usually tied to the high availability of natural sources of CO<sub>2</sub> and CO<sub>2</sub> transporting pipelines. Especially in the Permian Basin, the majority of the CO<sub>2</sub> consumed is from commercial natural reservoirs known as the McElmo Dome and the



Sheep Mountain Fields in Colorado, the Bravo Dome region in New Mexico, and the La Barge Field in Wyoming. Another important reason that explains the growing number of CO<sub>2</sub> projects is the relatively low cost of using CO<sub>2</sub> as a displacing agent compared to other alternatives.

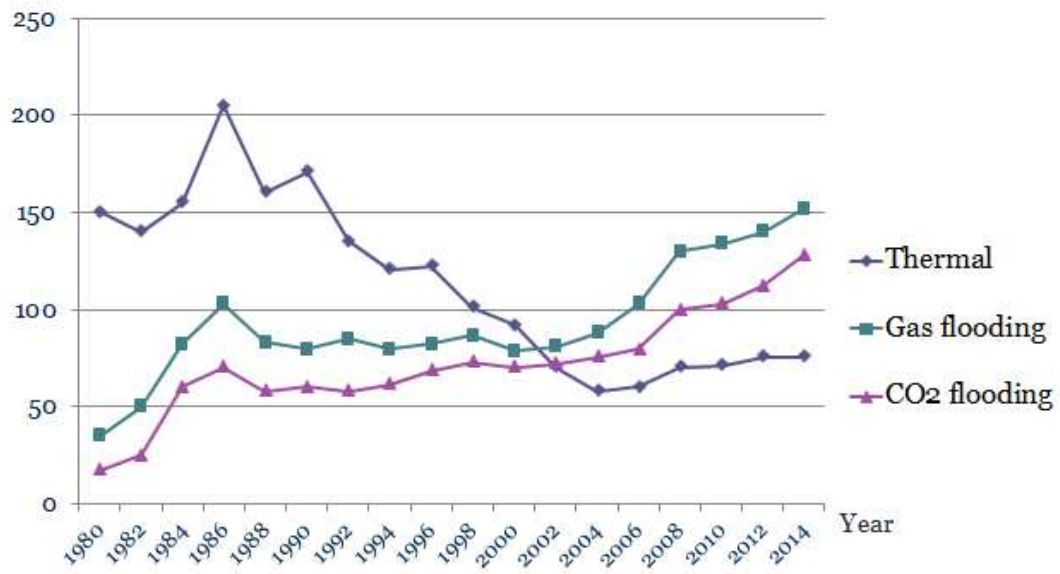


Figure 4.2. The number of thermal, gas flooding, and CO<sub>2</sub> flooding projects vs. year

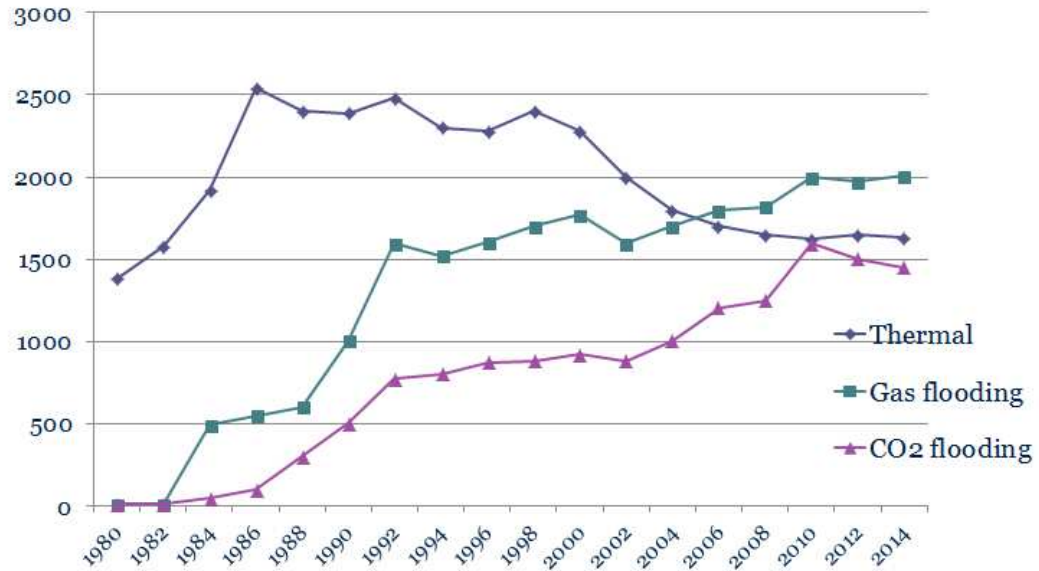


Figure 4.3. Production of thermal, gas flooding and CO2 flooding projects with year

**4.1.3. Data Cleaning.** Before data analysis, it is necessary to conduct data cleaning to ensure the quality of the results. The most common problems with field data are the missing data values and outliers. Some datasets have incomplete parameters or missing information including: oil viscosity, saturation, and reservoir permeability. The reasons for missing data are mostly from newly developed projects or projects that are rarely reported. Even though missing information can be roughly estimated by relating parameters, these partial-information projects miss more than one data value making the current information inadequate to estimate missing data. This missing data is neglected during data analysis.

Because of the complications of reservoir conditions, some parameters are provided as a range instead of a specific value. This situation is common for carbonate reservoir permeability. When fractures exist, the permeability of the rock matrix and fractures are remarkable different. For the permeability that is provided as a range, an

average permeability is used for data analysis. Average permeability was collected from published reports and other publications. Table 4.2 below is an example of original data and cleaned data.

Table 4.2. Data cleaning for permeability range

Operator	Field	Lithology	Original data (md)	Cleaned data (md)
Hess	Seminole Unit- ROZ Phase 1	Dolomite	1.3 - 123	6
Hess	Seminole Unit- ROZ Stage 1	Dolomite	1.3 - 123	6

Boxplots help detect outliers in the dataset. A box plot is created by describing the following five values of a dataset: minimum, 1<sup>st</sup> quartile, median, the 3<sup>rd</sup> quartile, and maximum. A schematic of a box plot and outlier detection is shown below.

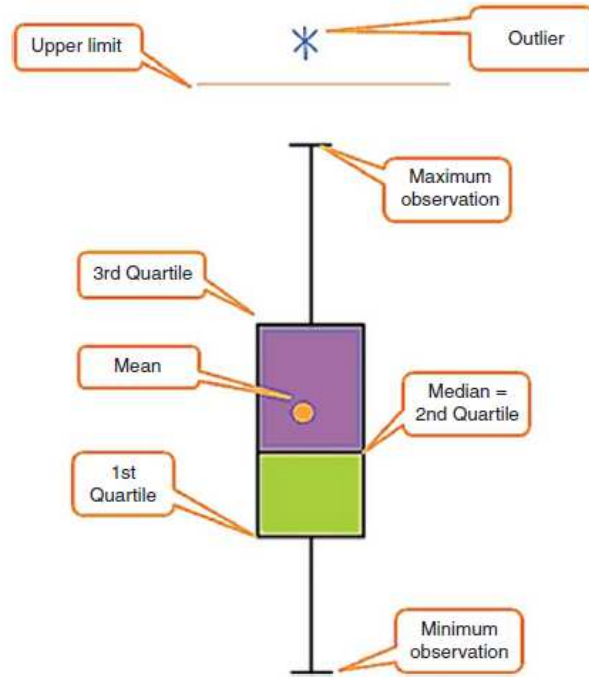


Figure 4.4. Schematic of a boxplot and outlier (Saleh *et al*, 2014)

An outlier is defined as a data value that is larger than the upper limit or smaller than the lower limit. Upper and lower limits are defined according to the principles below:

$$\text{Upper limit} = 3^{\text{rd}} \text{ quartile} + 1.5 * (3^{\text{rd}} \text{ quartile} - 1^{\text{st}} \text{ quartile})$$

$$\text{Lower limit} = 1^{\text{st}} \text{ quartile} - 1.5 * (3^{\text{rd}} \text{ quartile} - 1^{\text{st}} \text{ quartile})$$

If the calculated lower limit is a negative value, it can be ignored.

**4.1.4. Numerical Analysis.** After data cleaning, some numerical methods were applied to each reservoir property for analysis and correlation. Numerical methods include pie chart, histogram, and boxplot, cross plot.

#### Pie Chart

A pie chart is a graph which is divided into slices to illustrate numerical proportions. In a pie chart, the sum of all proportions is equal to 1. Data can be seen

through observation on a pie chart and percentages can be compared by observing the central angle and area of each section.

### Histogram

Histograms are used to display the distribution of a dataset. It shows frequency on the y-axis and the variations on the x-axis. The peak or the few peaks of a histogram indicate the most frequent range that the values appear.

### Boxplot

A boxplot is used not only for outlier detection, but also for displaying data. The upper and lower boundaries of the “box” are outlined by the interquartile range, which is the difference between the 3<sup>rd</sup> and 1<sup>st</sup> quartiles:  $IQR = Q_3 - Q_1$ . Boxplots shows the values and the main range of each dataset.

### Cross Plot

A cross plot is used to plot a pair of related variables from the dataset. In this study, cross plots are mainly used to find relationships between MMP and reservoir characteristics.

## **4.2. DATA ANALYSIS**

This section is the analysis of the dataset collected from 134 CO<sub>2</sub> projects. Data includes reservoir properties, reservoir fluid properties, and operation parameters.

**4.2.1. Project Evaluation.** Out of the 134 CO<sub>2</sub> flooding projects, 91 projects were evaluated as successful. Oil recovery was enhanced significantly after CO<sub>2</sub> injection. Commercial successes were also achieved through these projects. 18 projects were considered as promising. As favorable enhanced oil recovery methods are developed

either by continuous injection or strategy adjustment, satisfactory recovery may be reached. 15 projects are still at the early stage of CO<sub>2</sub> injection and are not ready to be evaluated. 7 projects were assessed as discouraging. These projects barely provide any enhanced oil recovery and made unfavorable profit. Evaluations of the other 3 projects were not available. The pie chart below shows the proportion of the different assessments. Overall, about 82% of the projects were encouraging and only 5% of the projects were unsuccessful.

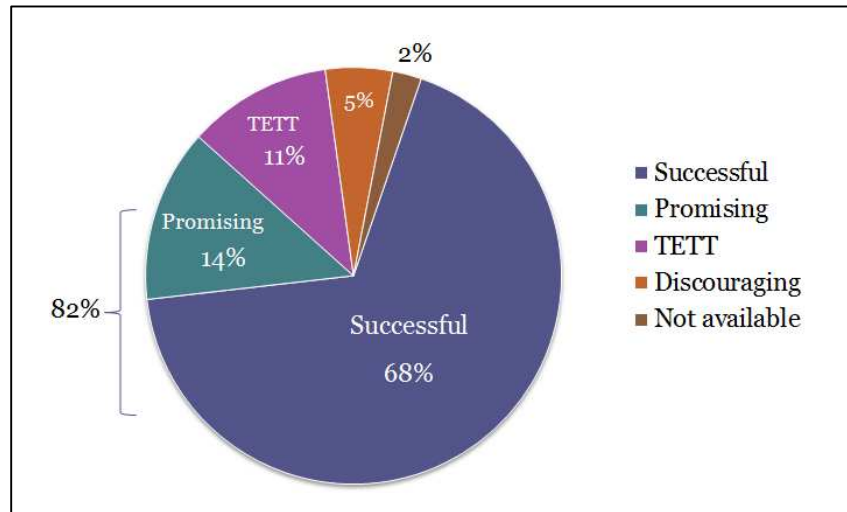


Figure 4.5. Evaluations of 134 CO<sub>2</sub> projects.

**4.2.2. Reservoir Properties.** The following data analysis below is the dataset excluding the 7 unsuccessful projects.

**4.2.2.1 Reservoir lithology.** Figure 4.6 below shows the percentage of CO<sub>2</sub> flooding project applications in different formation types in the last three decades. The pie chart indicates that about 55 percent of the projects were applied in carbonate

reservoirs while about 37 percent in sandstone reservoirs. The other six percent were implemented in tripolite reservoirs. It is reported that CO<sub>2</sub> flooding is not sensitive to reservoir lithology. There are more projects in carbonate reservoirs than in sandstone reservoirs because the largest CO<sub>2</sub> field in the U.S. is in the Permian Basin, which is dominated with carbonate rocks.

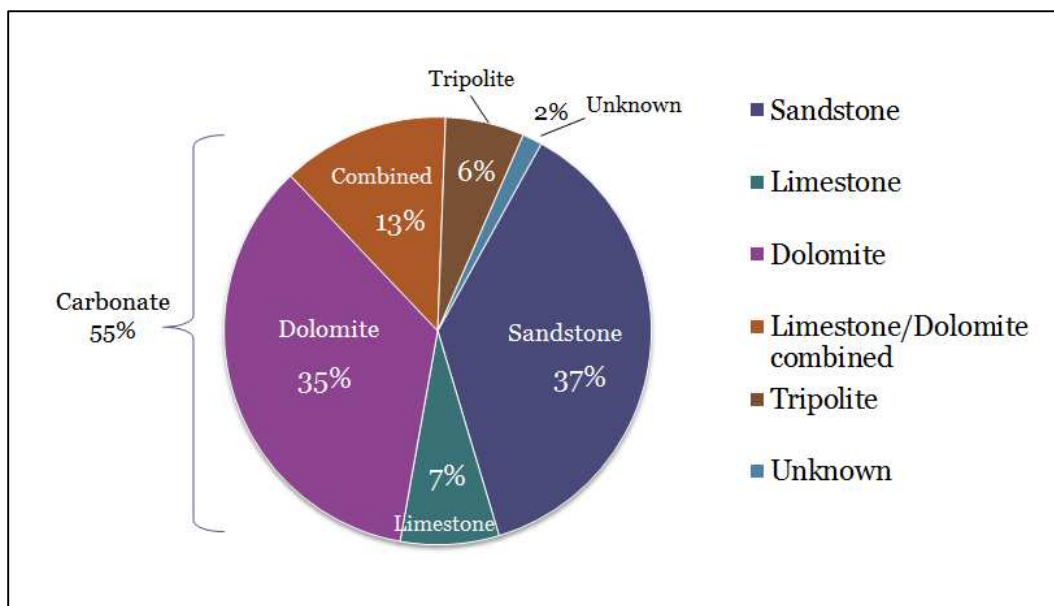


Figure 4.6. Reservoir lithology distributions of 127 projects

**4.2.2.2 Reservoir porosity.** A histogram and a box plot were generated to display the distribution of the porosity for the 126 projects. The range of porosity is from 4 to 29.5%. Two outliers were detected from the box plot. It can be observed that the histogram is distributed in a skewed shape. The three highest peaks are in the range from 9 to 17% as shown in the Figure 4.7. The box plot in Figure 4.8 shows the average is 14.3% and the median is 12%.

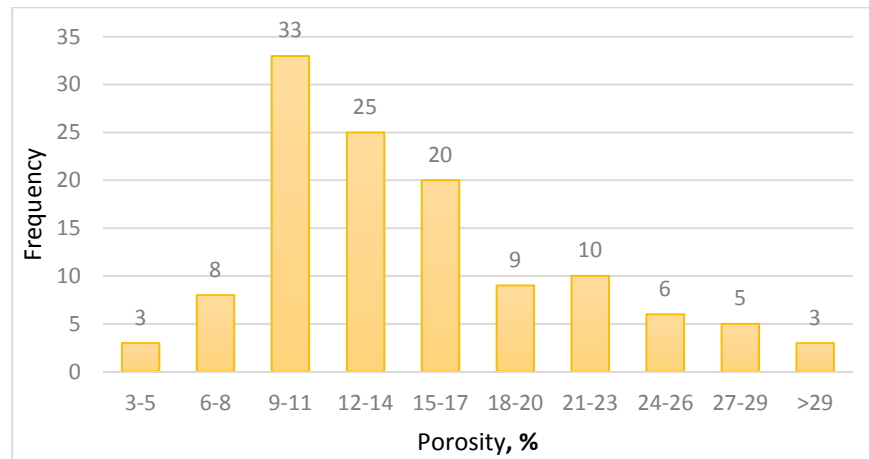


Figure 4.7. Reservoir porosity (%) distributions histogram

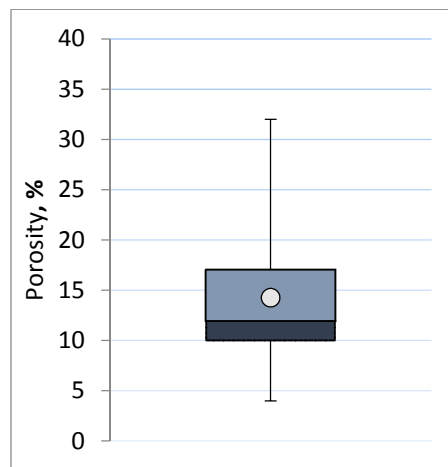


Figure 4.8. Reservoir porosity (%) distributions boxplot

Both the histograms and boxplots look different when the porosity distributions are separated into sandstone and carbonate reservoirs. Distributions for the two types of reservoirs are shown in the figures below.



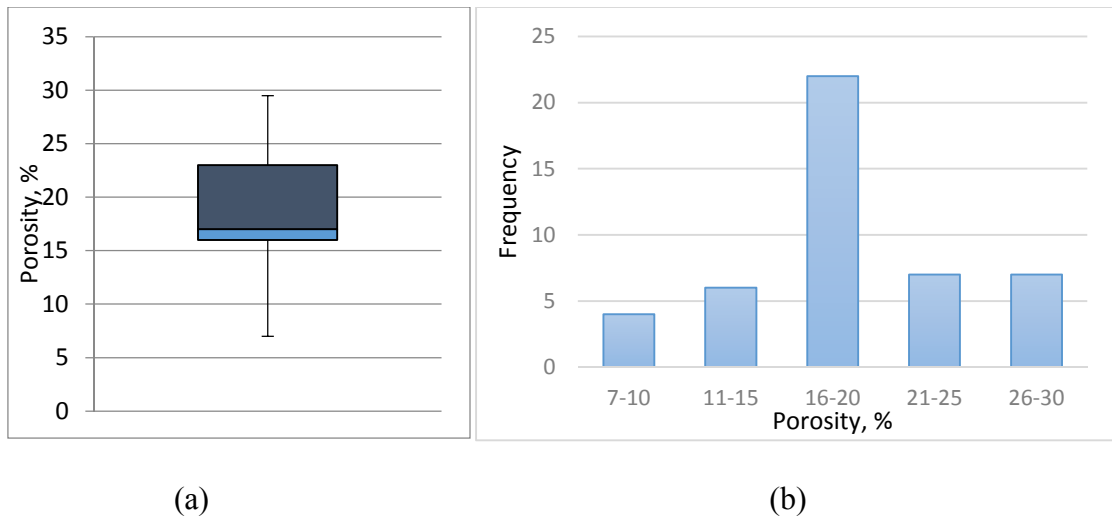


Figure 4.9. Porosity distributions of sandstone reservoirs (a) box plot and (b) histogram

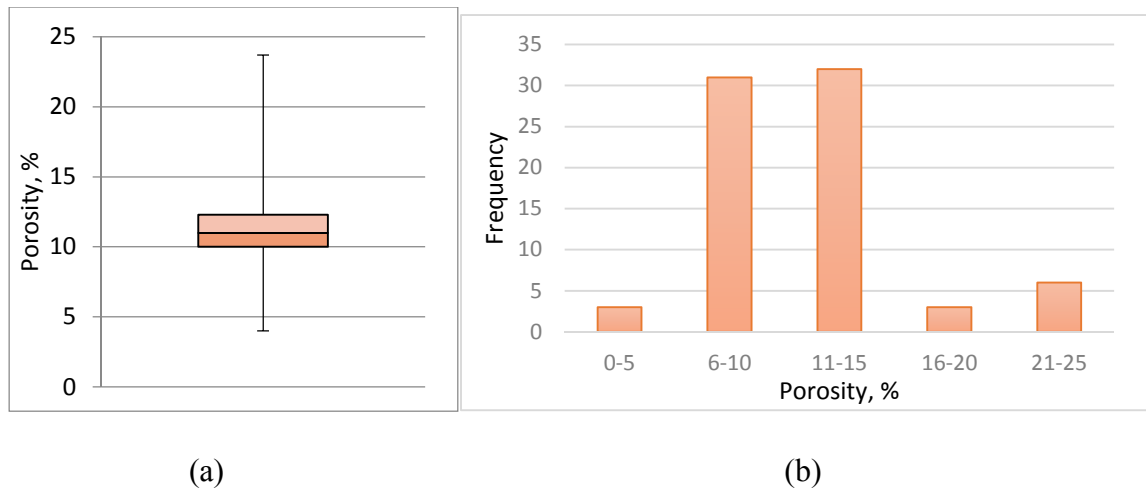


Figure 4.10. Porosity distributions of carbonate reservoirs (a) box plot and (b) histogram

For the sandstone porosity distribution, it can be seen that the porosity range is from 7 to 30% and the histogram displays a normal shape. The maximum peak is from the range of 16-20%. For the carbonate reservoirs, the box plot shows that the porosity is

distributed more concentratedly. Most of the data falls into the ranges of 6-10% and 11-15%. A better comparison can be seen from the histogram below. Porosities are distributed in the smaller ranges for carbonate reservoirs than the sandstone ones.

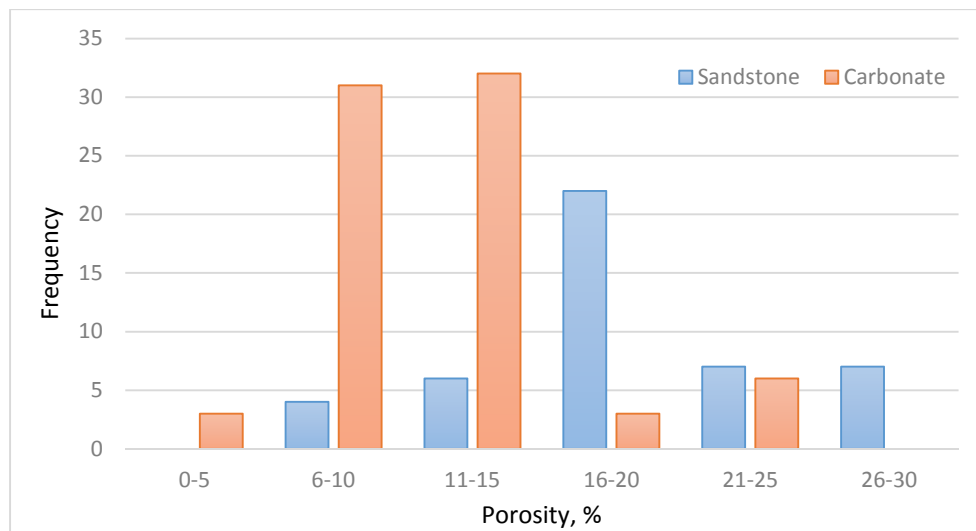


Figure 4.11. Comparison of porosity distributions between sandstone and carbonate reservoirs

**4.2.2.3 Reservoir permeability.** After data cleaning, permeability data from 125 out of 127 projects were analyzed. The permeability of those 125 projects is in a reverse J distribution as displayed in Figure 4.13 and ranges from 2 to 700 mD as shown in the boxplot below. The boxplot also indicates that most permeability values fall into the range of 0-50 mD. Carbonate reservoirs are predominately in the low permeability range of the distribution.

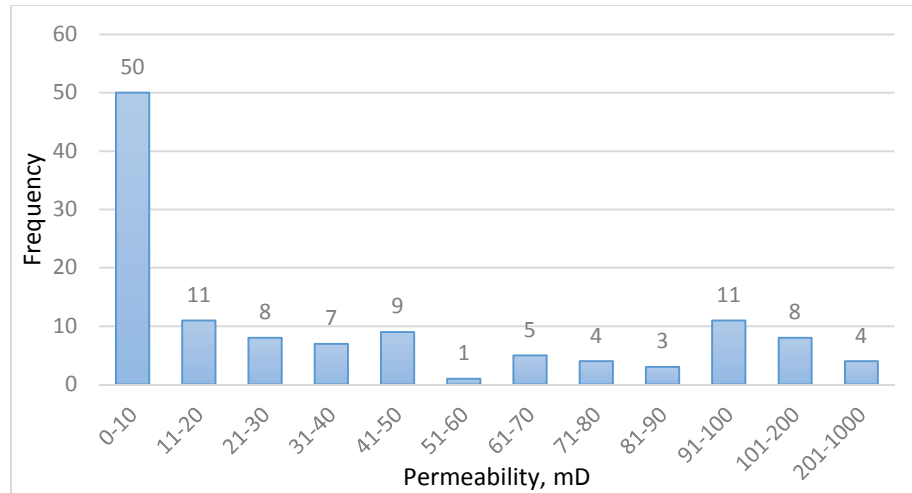


Figure 4.12. Permeability distribution histogram

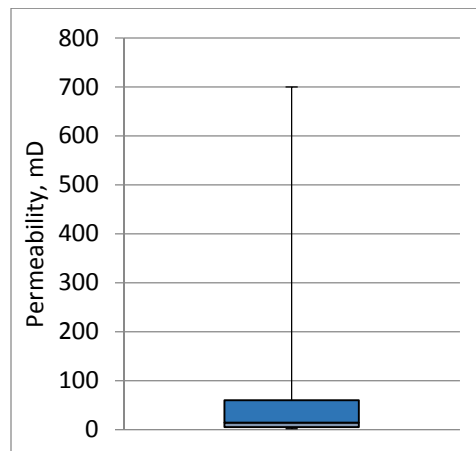


Figure 4.13. Permeability distribution boxplot.

In Figure 4.15 below, permeability of sandstone and carbonate reservoirs were marked in different colors for a better comparison. The sandstone permeability (blue) is evenly distributed on the x-axis. The carbonate reservoirs permeabilities (red) are distributed extremely. Almost half of the permeabilities are below 10 mD while about 20% of the permeabilities are greater than 100 mD. The reason for this phenomenon is that

carbonate reservoirs in general, are naturally fractured geologic formations characterized by heterogeneous porosity and permeability distributions (Manrique *et al*, 2007).

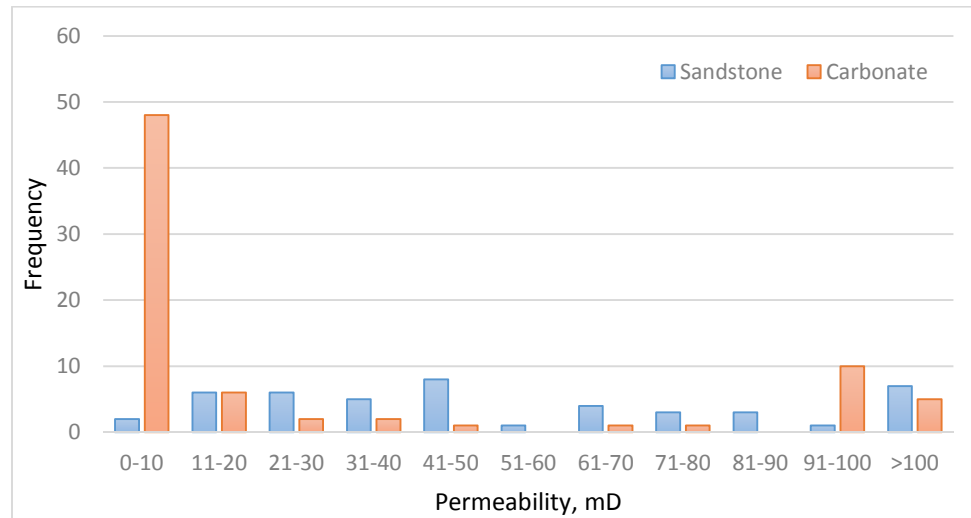
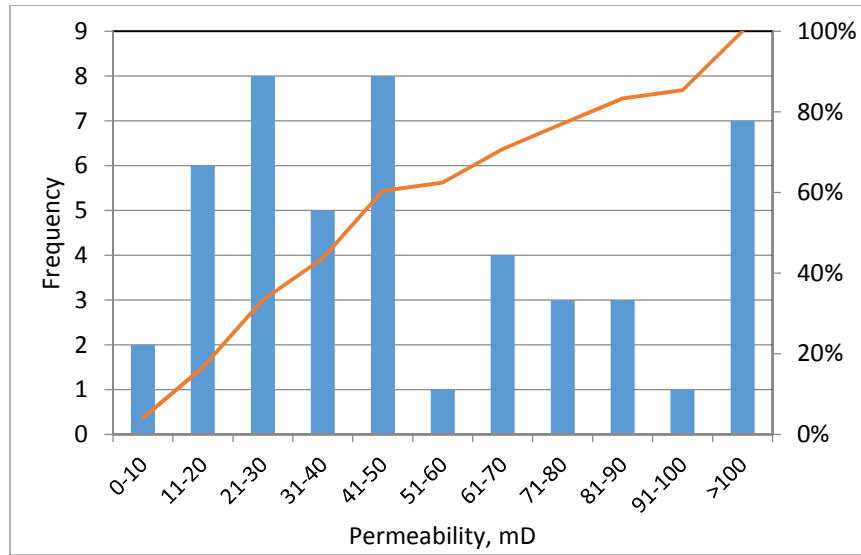
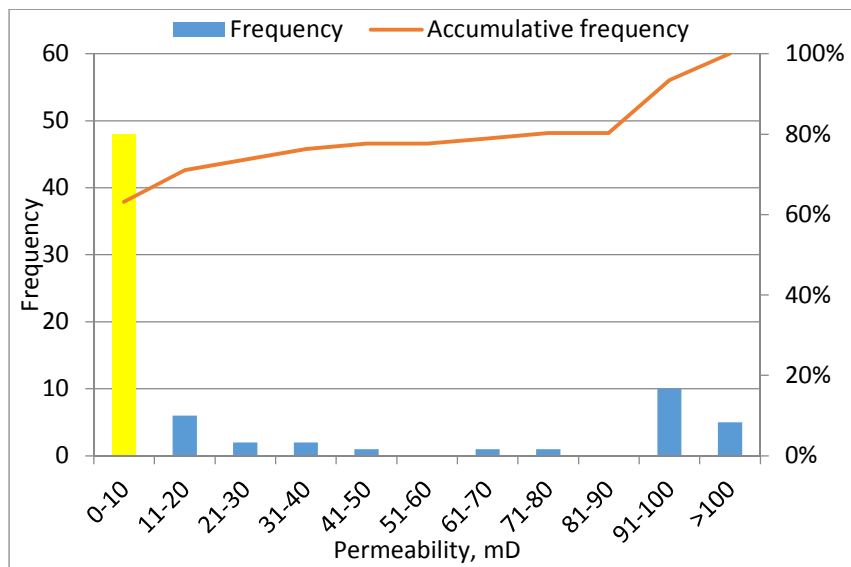


Figure 4.14. Comparison of sandstone and carbonate reservoir permeability distributions.

In Figure 4.15, accumulative permeability frequency curves are generated based on permeability distribution histograms. The curve of sandstone reservoir permeability has a linear trend which indicates even distribution. The curve of carbonate reservoir permeability, however, has a mild trend after the first peak. The curve spikes where the Permian Basin carbonate reservoirs occur. The carbonate reservoir accumulative frequency curve becomes steep at the range greater than 91 mD where there are a group of high permeable reservoirs.



(a)



(b)

Figure 4.15. Comparison of sandstone (a) and carbonate (b) reservoir permeability distributions.

**4.2.2.4 Reservoir temperature.** Reservoir temperature is an important parameter in a CO<sub>2</sub> flooding operation. CO<sub>2</sub> minimum miscibility pressure is a direct function of

temperature and it increases linearly corresponding to temperature (Jarell *et al*, 2002). MMP increases as temperature increases. For some high temperature reservoirs, achieving miscible flooding is impossible because if the MMP is higher than the formation fracture pressure, injection at MMP will cause the formation to fracture and thus creating CO<sub>2</sub> pathways.

Reservoir temperature was obtained from 124 projects. Figure 4.16 shows the distribution of the reservoir temperatures. The minimum is 83 °F and the maximum is 260 °F. The maximum temperature is from the Cranfield reservoir in Mississippi where the temperatures of 11 projects in the nearby area are above 220 °F. In these cases, CO<sub>2</sub> minimum miscibility pressures were calculated above 3000 psi.

According to an empirical correlation of CO<sub>2</sub> MMP provided by the National Petroleum Council, for reservoir temperatures greater than 120 °F, additional pressure is needed to achieve miscibility. Additional pressure ranges from 200 to 500 psi. Thus, for CO<sub>2</sub> miscible flooding, reservoir temperatures less than 120 °F are preferred. As shown in the histogram below, more than 50% of the reservoir temperatures are lower than 120 °F.

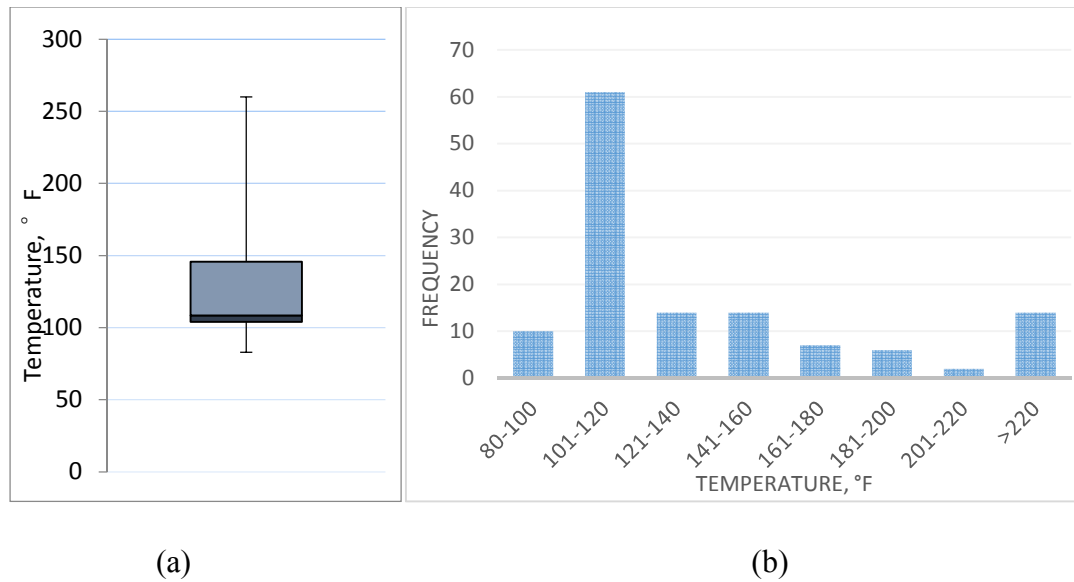
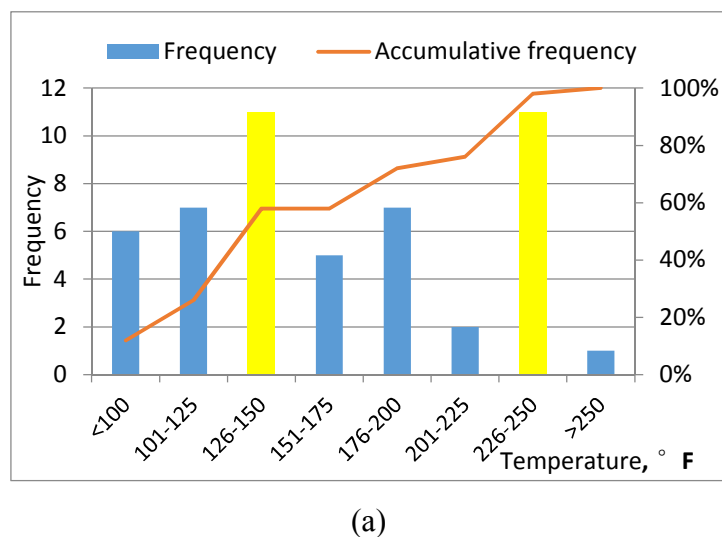
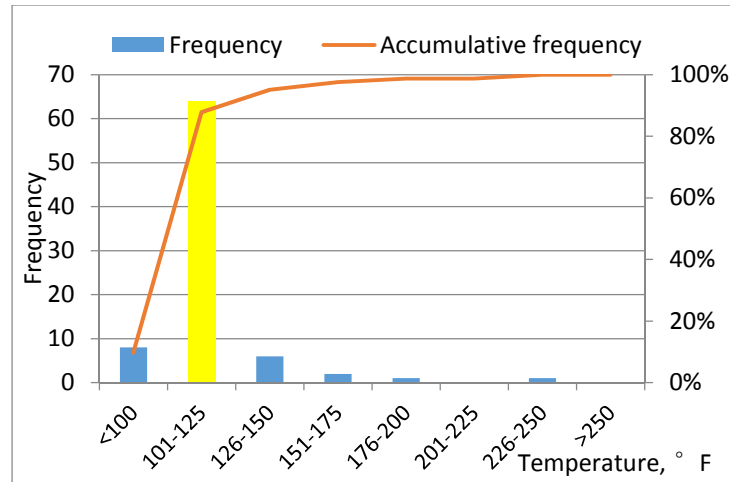


Figure 4.16. Reservoir temperature distributions (a) box plot and (b) histogram

The accumulative frequency curves of the temperatures for the two types of reservoirs are similar to the permeability ones. As shown in the Figure 4.17 (a), sandstone reservoirs have a linear-like trend while carbonate reservoir distribution is totally dominated by the Permian Basin carbonates.





(b)

Figure 4.17. Sandstone (a) and carbonate (b) reservoirs CO<sub>2</sub> injection temperature distribution comparison

Although there is no direct relationship between lithology and reservoir temperature, the distribution shows a significant difference between sandstone and carbonate reservoir temperatures. One probable reason is that carbonate reservoirs have relatively lower fracture pressure than sandstone reservoirs. The carbonate reservoirs that have a temperature lower than 120 °F are better candidates than carbonate reservoirs with higher temperatures.



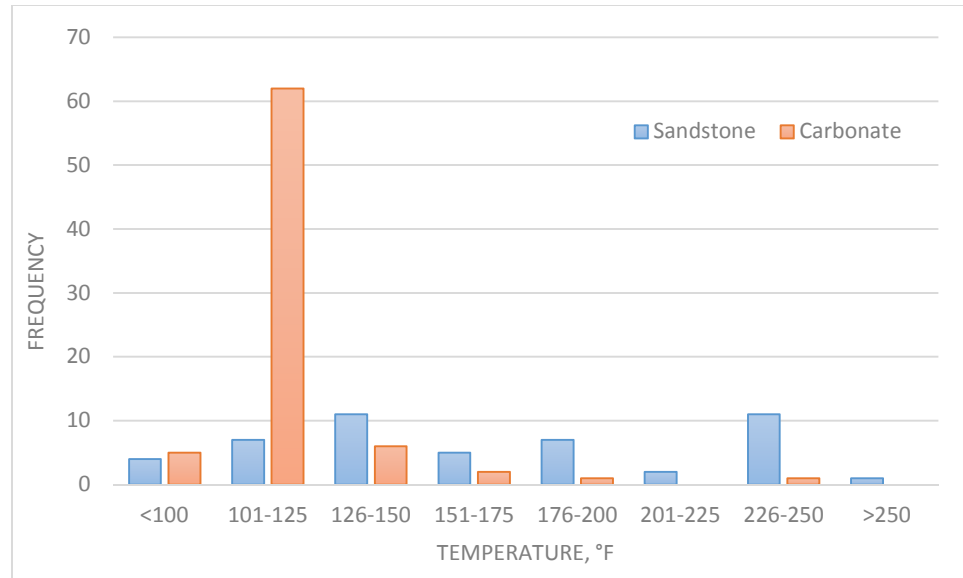
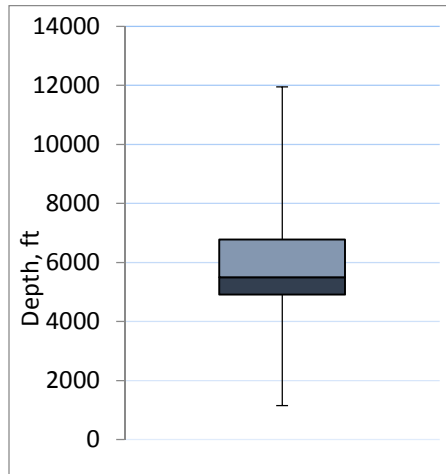


Figure 4.18. Sandstone and carbonate reservoir temperature distributions.

**4.2.2.5 Reservoir depth.** As mentioned previously, there is a threshold depth for CO<sub>2</sub> miscibility with reservoir oil. Two widely accepted CO<sub>2</sub> miscible threshold depths are 2,500 ft (Taber, 1997; Gao *et al*, 2010) and 3,000 ft (Arshad *et al*, 2009). Even though 2,500 ft is taken as the threshold depth, there are 6 projects that have CO<sub>2</sub> injected below this depth. From the boxplot in Figure 4.18, the depth is as shallow as 1,150 ft which is much shallower than 2,500ft.

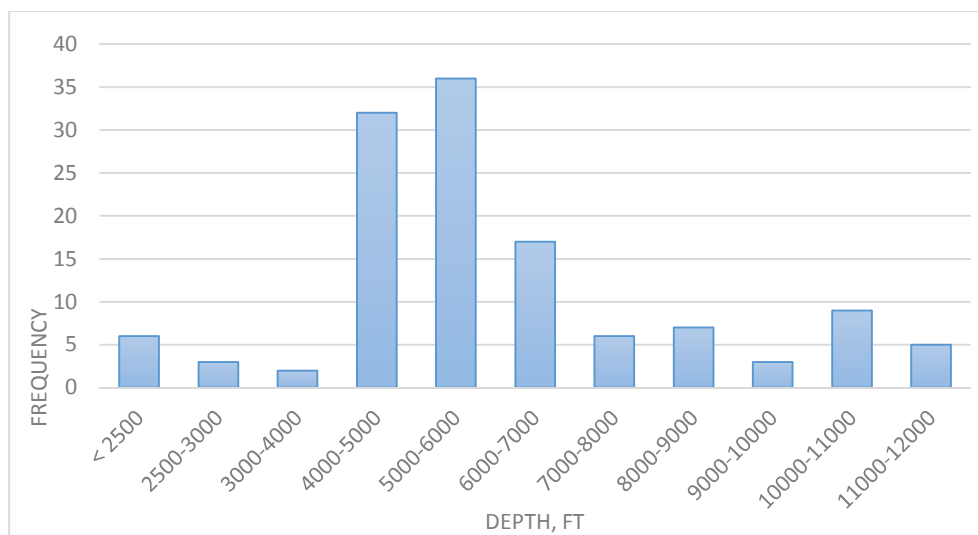
Five out of six low-depth projects are from the Salt Creek field which is located in Natrona County, Wyoming. Literature shows that the field has an initial pressure of 1,750 psi. Oil gravity varies from 35 to 39 °API while the reservoir temperature varies from 99 to 112 °F. Using the oil gravity and temperature, the minimum miscibility pressure can be roughly estimated in Figure 4.19. The estimated MMP is in the range of 1300 to 1500 psi which is smaller than the initial reservoir pressure. Miscibility can be achieved in such conditions. The other shallow field is the Northwest Velma Hoxbar field that is

located in central Oklahoma. There is no current literature available for this field. According to the dataset, the Northwest Velma Hoxbar field has a temperature of 84 °F, oil gravity of 27 °API, and viscosity of 2.4 cp. MMP is estimated to be below 1,500 psi from Figure 4.19. Even though low temperatures provide a favorable condition for miscibility, it is remarkable that 84°F is below the carbon dioxide critical temperature (88 °F) which means the CO<sub>2</sub> is miscible with the oil in a liquid state. In a liquid state, CO<sub>2</sub> is more viscous and denser compared to being in a gas or supercritical state.



(a)

Figure 4.19. Reservoir depth distributions (a) box plot and (b) histogram



(b)

Figure 4.19. Reservoir depth distributions (a) box plot and (b) histogram(cont.)

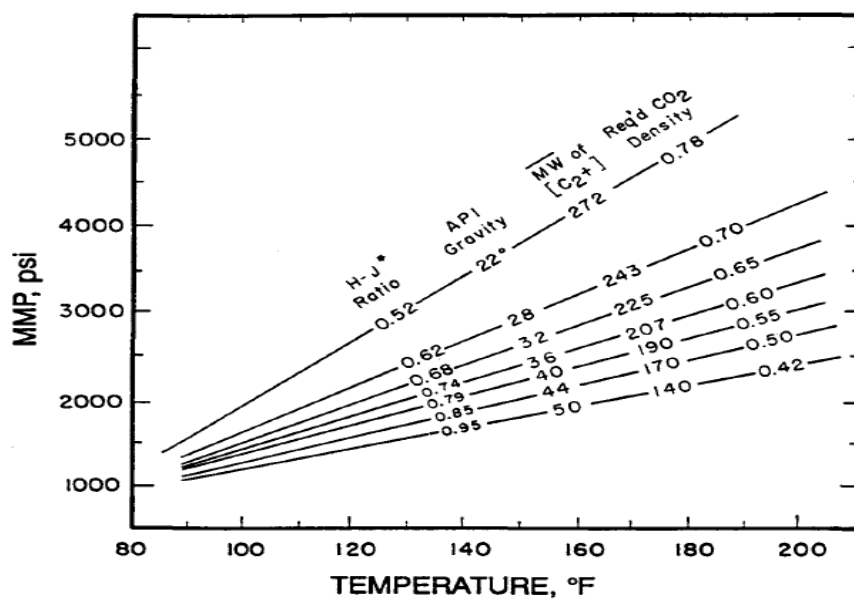


Figure 4.20. Variation of MMP with temperature and oil composition (Holm, 1987)

The comparison between sandstone and carbonate reservoirs depth distribution is similar to the temperature distribution. There is no clear relationship between depth and reservoir lithology, possibly due to more carbonate projects than sandstones.

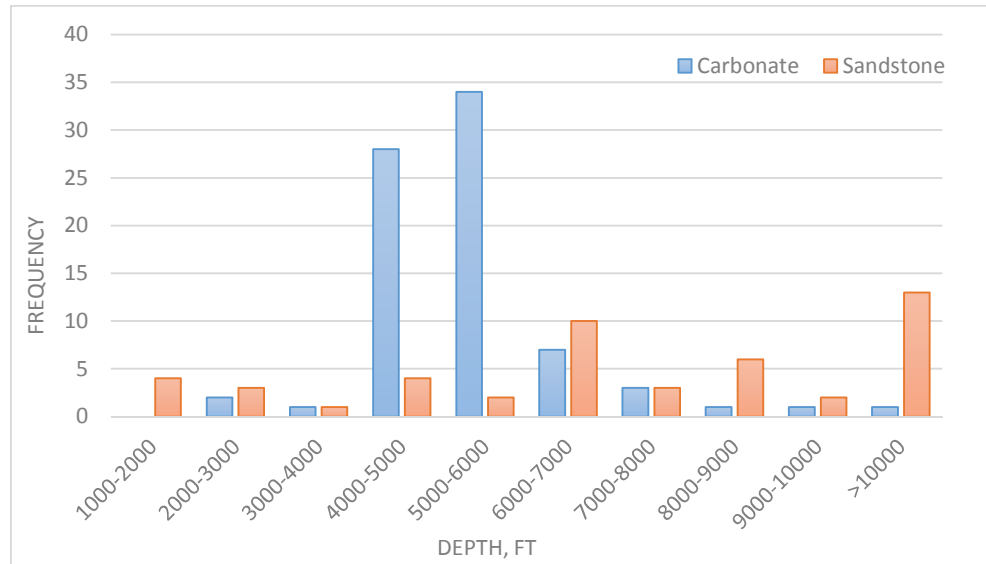


Figure 4.21. Sandstone and carbonate reservoirs CO<sub>2</sub> injection depth distribution comparison

**4.2.2.6 Reservoir oil saturation.** Even though reservoir oil saturation is not a main factor that CO<sub>2</sub> displacement depends on, many researchers still take it into account as a rough guideline for economic concern. Generally, for successful CO<sub>2</sub> miscible flooding, oil saturation should not be less than about 20% pore volume (Gao *et al*, 2010). As shown in Figure 4.22, the oil saturation at the beginning of the projects is as high as 89% pore volume among 108 projects. The average value is about 50% pore volume

which indicates good reservoir candidates. The minimum value is 26.3% pore volume which is greater than the screening criteria limit mentioned above.

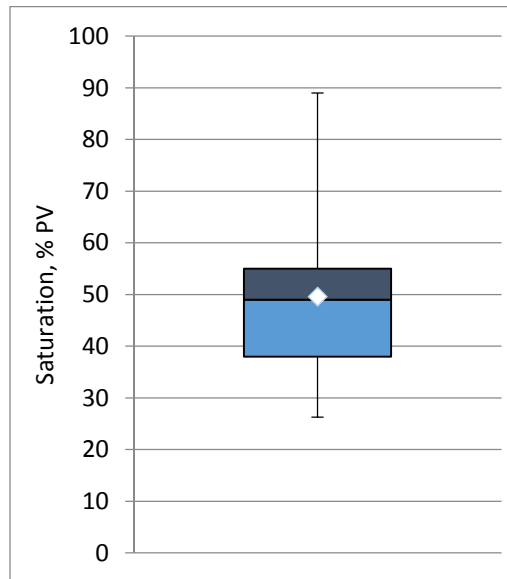


Figure 4.22. Beginning reservoir oil saturation (%PV) boxplot.

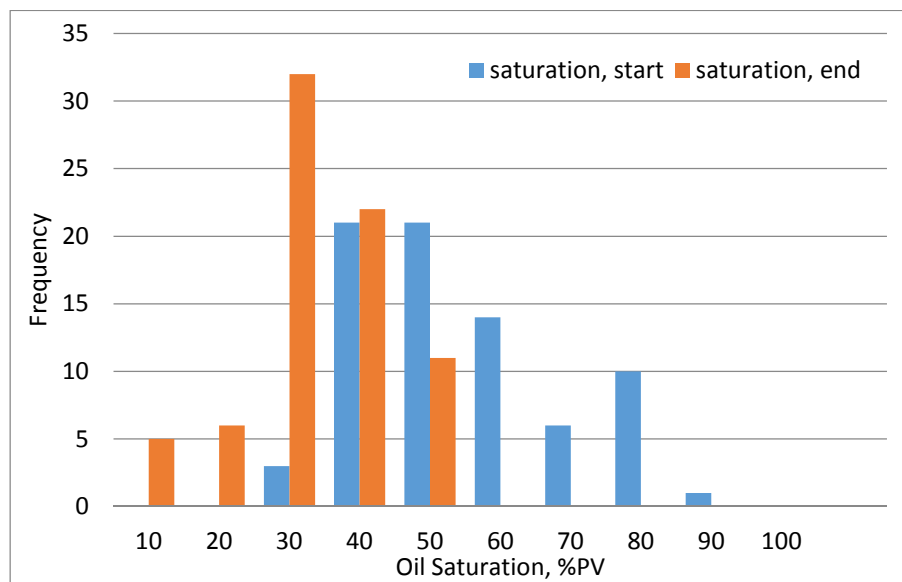


Figure 4.23. Beginning oil saturation vs. remaining oil saturation as of 2014.

**4.2.2.7 Net pay thickness.** Although reservoir net pay thickness is not considered as a screening criteria for CO<sub>2</sub> flooding by previous researchers, it is regarded as a critical parameter for flooding success estimation. Thick net pay is economic and productively beneficial while thin layers could avoid CO<sub>2</sub> gravity segregation to some extent. According to Song (2014), when the net thickness is less than 30 m (98.4 ft), the increase of the net thickness would increase the technical efficiency of WAG flooding.

The net pay thickness summarized from 25 CO<sub>2</sub> miscible flooding projects is shown in Figure 4.24. This value has a range of 15 – 268 ft. Most of the values are in the range of 75 – 137 ft which indicates both economic and recovery favorable.

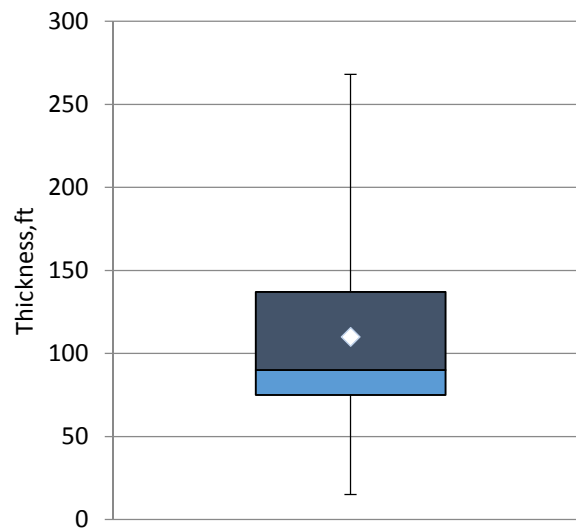


Figure.4.24. CO<sub>2</sub> flooding projects reservoir net pay thickness distribution boxplot

**4.2.2.8 Reservoir permeability versus porosity** In many consolidated sandstone and carbonate formations, a plot of the logarithm of permeability is often linearly proportional to porosity (Nelson, 2000). However, carbonates reservoirs are tight and

inherently heterogeneous (Shabaninejad *et al*, 2011). A crossplot of the logarithm of permeability and porosity of two types of reservoirs are shown in Figure 4.23 and 4.23 below. Figure 4.25 shows a linear trend for the sandstone reservoirs while Figure 4.26 shows a tendency of heterogeneity in the carbonate reservoirs.

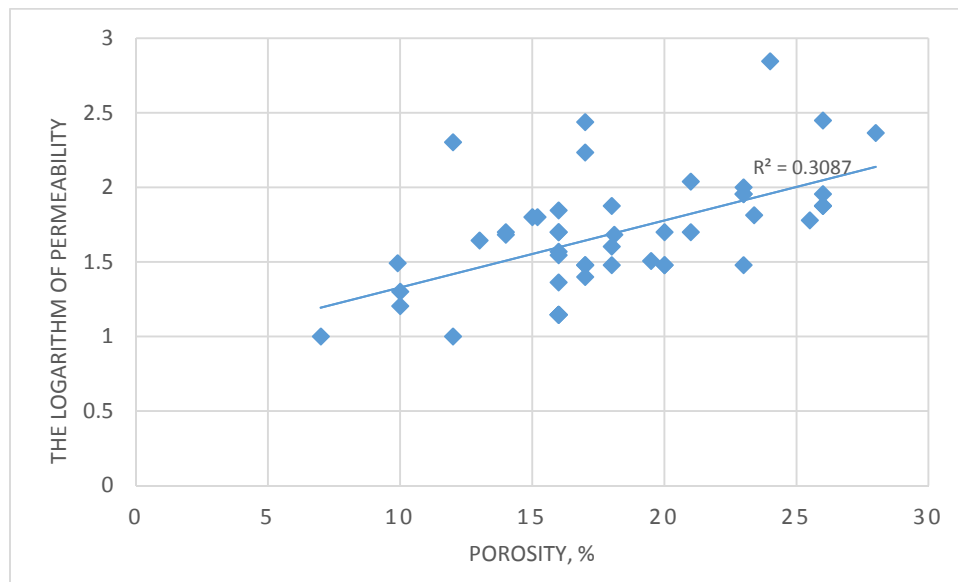


Figure 4.25. The logarithm of permeability vs. porosity in sandstone reservoirs

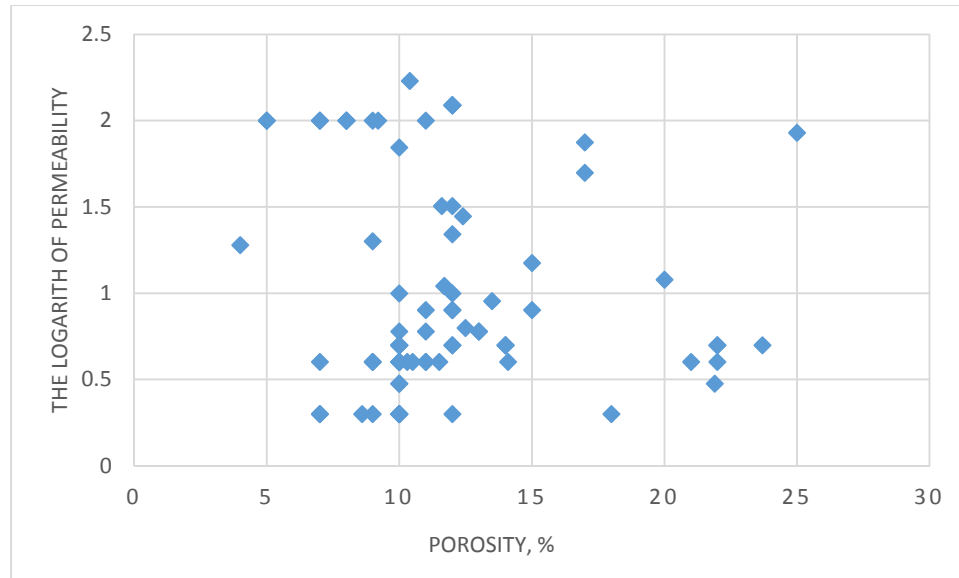


Figure 4.26. The logarithm of permeability vs. porosity in carbonate reservoirs

**4.2.3. Reservoir Fluid Properties.** Collected reservoir fluid properties include oil gravity and oil viscosity. Typically, oil composition is described using only the gravity. The unit “API” stands for the American Petroleum Institute. API gravity is a measurement of how heavy the oil is.

Table 4.3. Crude Oil Classification

Oil classification	API Gravity
Light oil	> 31.1
Medium oil	22.3 - 31.1
Heavy oil	10 - 22.3
Extra heavy oil	< 10



Factors that affect viscosity are oil composition, temperature, dissolved gas, and pressure. Normally, the heavier the oil is or the smaller the API gravity is, the more viscous the oil will be. Above the bubblepoint pressure, the viscosity increases with pressure increase. The viscosity is lower with higher temperatures.

**4.2.3.1 Oil gravity.** 125 projects provided oil gravity data, most of the values are between 32 to 43 °API which indicates light oil reservoirs. The heaviest oil is 27 °API from the Northwest Velma Hoxbar field in Oklahoma. Relatively shallow reservoirs account for slightly heavier oil gravities.

Theory and field applications both demonstrate that light oil reservoirs are better candidates for CO<sub>2</sub> miscible flooding.

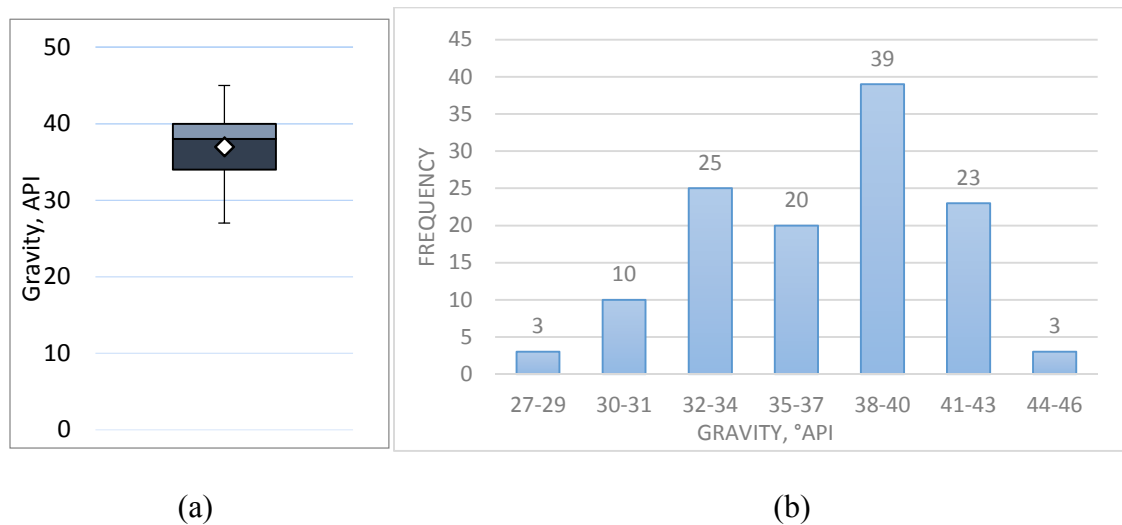


Figure 4.27. CO<sub>2</sub> flooding oil gravity (°API) distribution (a) boxplot and (b) histogram

Although there is no direct relationship between reservoir lithology and oil gravity, the distribution histogram in Figure 4.28 shows a significant difference between the two types of reservoirs.

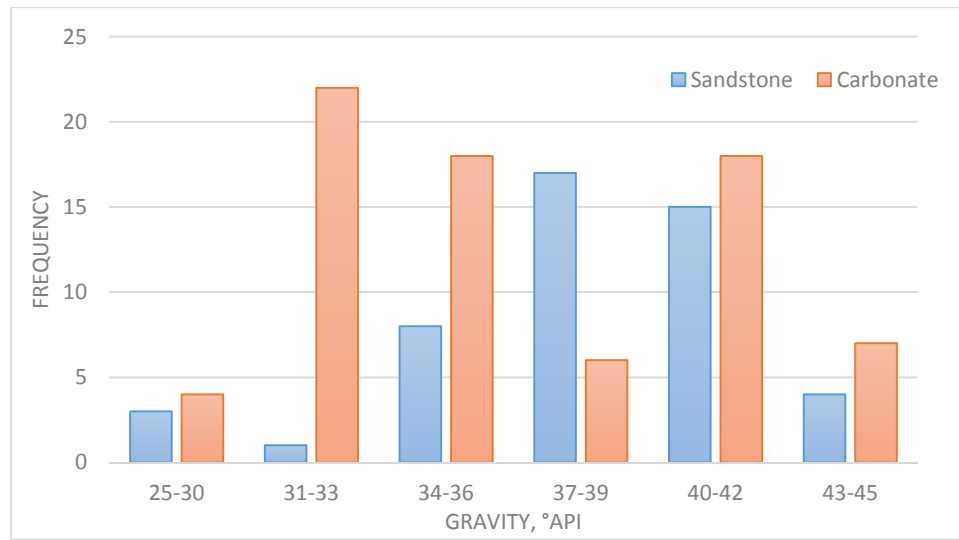


Figure 4.28. Sandstone and carbonate reservoir oil gravity distribution comparison

**4.2.3.2 Oil viscosity.** In consideration of the viscous fingering problem and other problems resulting from viscosity differences between carbon dioxide and crude oil, low viscous oil reservoirs are better candidates than viscous ones.

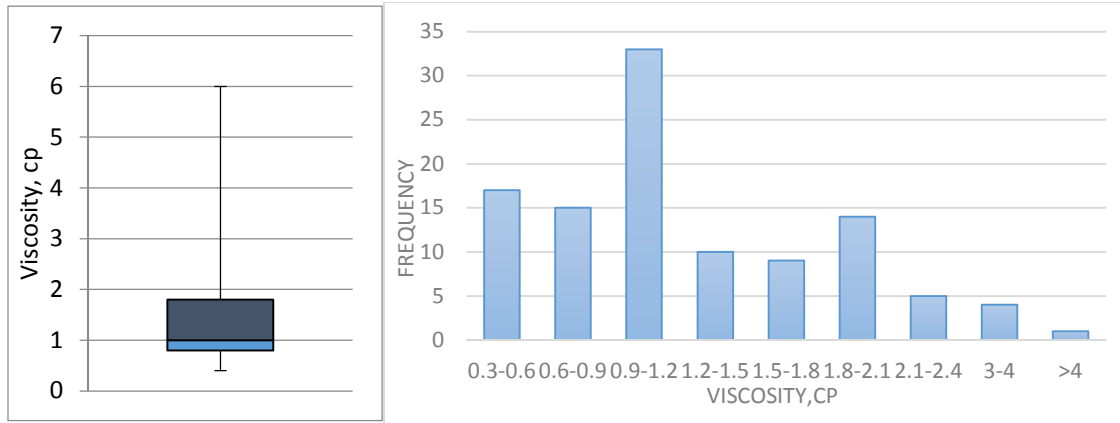


Figure 4.29. Oil viscosity distribution (a) boxplot and (b) histogram

**4.2.3.3 CO<sub>2</sub> minimum miscibility pressure.** Only 22 projects provided CO<sub>2</sub> minimum miscibility pressure data. MMP ranges from 1,020 psi to 3,452 psia, most in the range from 1,600 to 2,500 psia. CO<sub>2</sub> minimum miscibility pressure is generally considered to be greater than 1,400 psia well above 1,020 psia. The minimum value 1,020 psia is from the Goldsmith San Andres field. Minimum miscibility pressure is measured by slim tube experiments. A reservoir has favorable characteristics for low MMP when the temperature is 97 °F, crude oil is 37 °API, and oil viscosity is 0.7 cp (Jasek *et al*, 2007).

MMP could be lowered by the addition of additive gases such as SO<sub>2</sub> and H<sub>2</sub>S when reservoir pressure is insufficient to reach miscibility. In general, the CO<sub>2</sub> injection pressure is about 200 psia higher than the MMP to make sure miscibility can be achieved, or the pressure is between the MMP and the fracture pressure.

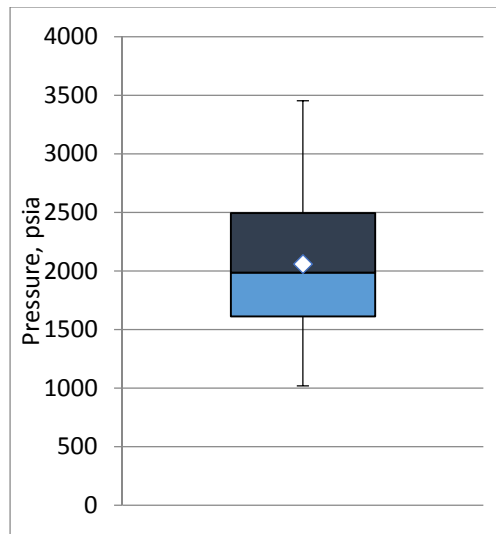


Figure 4.30. CO<sub>2</sub> MMP distribution boxplot

In Figure 4.31, a cross plot of MMP versus reservoir depth is generated. The overall trend is that MMP increases with the depth, but additional plot distributions show that MMP is determined by multiple factors.

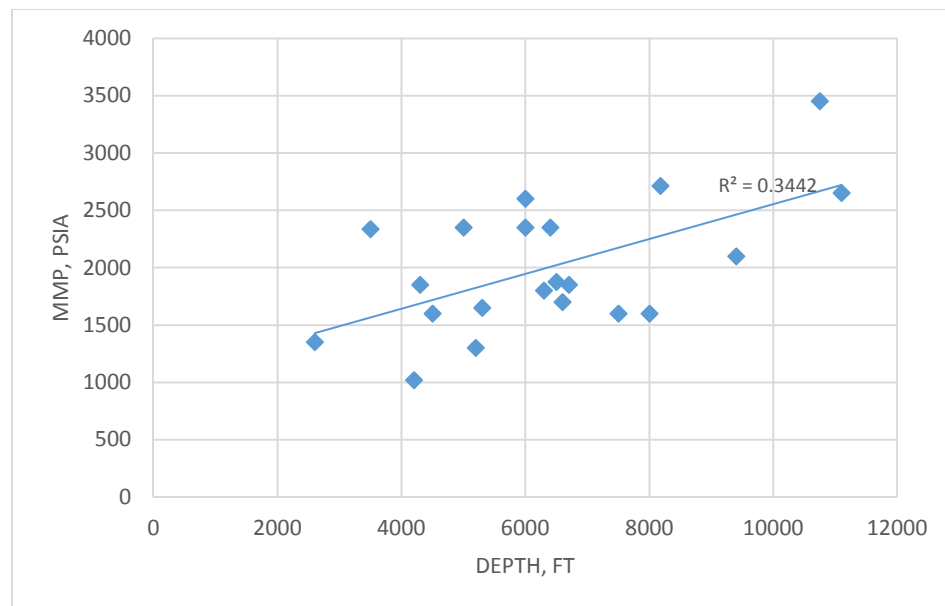


Figure 4.31. MMP with reservoir depth

A relationship between MMP and reservoir temperatures is displayed in Figure 4.32. As shown in the crossplot, MMP has a more linear trend when crossplotted with temperature.

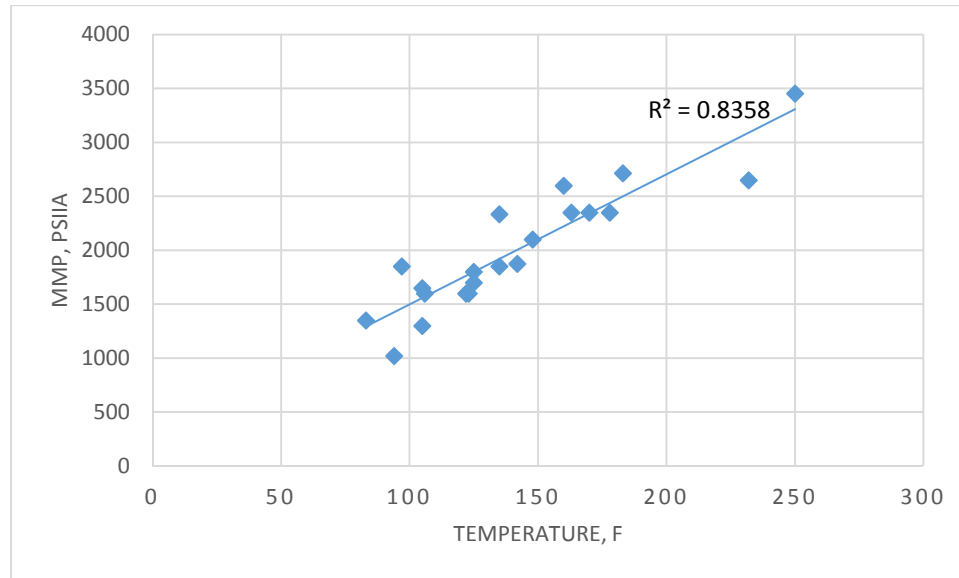


Figure 4.32. MMP with reservoir temperature

#### 4.2.4. Production data

Figure 4.33 shows the total and enhanced production rates from the year 2002 to 2014. Both total and enhanced production rates have been increasing for the 12 years. Most of the total production is from the enhanced production due to the CO<sub>2</sub> miscible flooding.

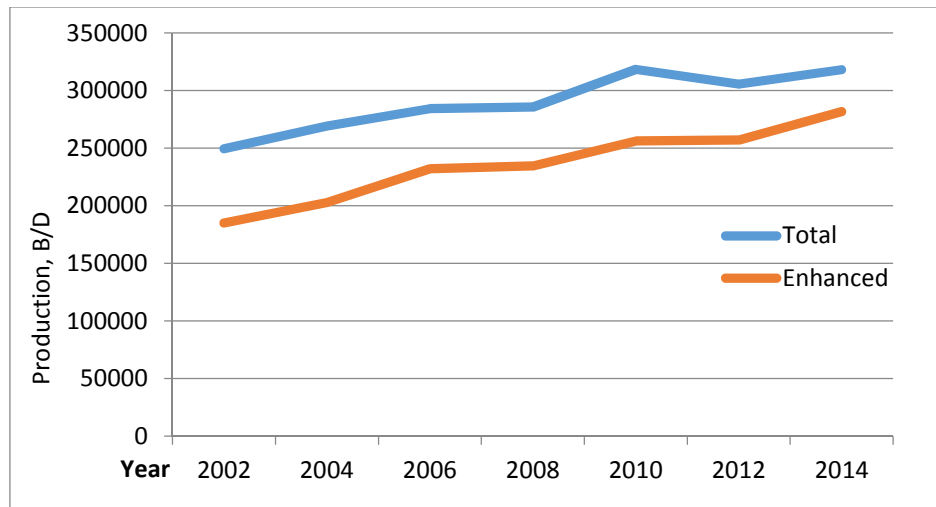


Figure 4.33. The trend of total and enhanced production rates from 2002 to 2014.

Among the 127 projects, 56 projects have been producing from the year 2002 to 2014. Every two years, production rates for each project were summarized and stacked up. A production rate vs. year histogram is generated and shown in Figure 4.34.

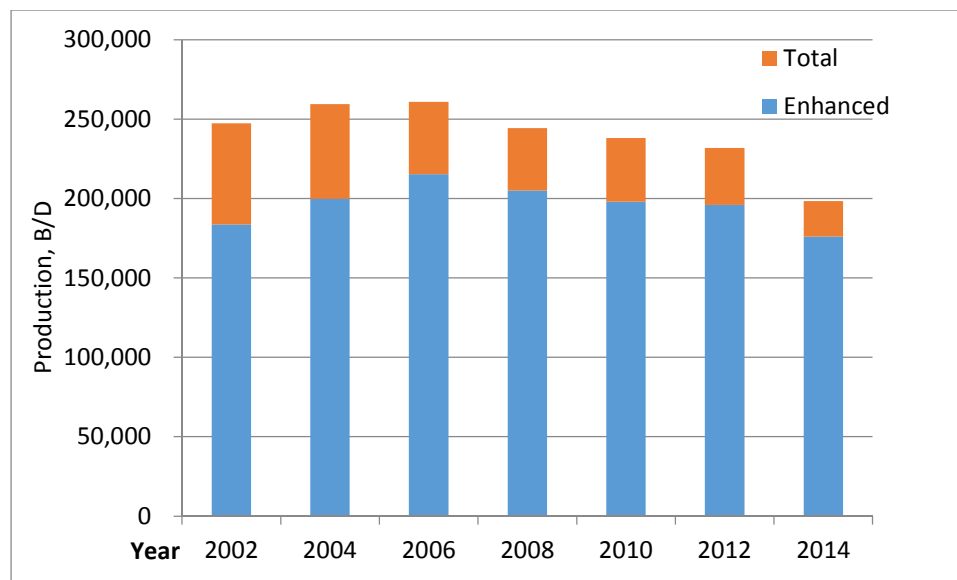


Figure 4.34. Histogram of the production rates of 56 projects through year 2002 to 2014

Most of the 56 projects started CO<sub>2</sub> miscible flooding around the year 2002. As shown in the histogram, both the total and the enhanced production rates increased when CO<sub>2</sub> was first injected. After four to five years of injection and production, with the decreasing volume of remaining oil in the reservoir, both the total production rate and the enhanced production rate have started to decline.

## 5. SUMMARY AND CONCLUSIONS

### 5.1. DATA SUMMARY

This paper summarizes CO<sub>2</sub> miscible flooding field application data and conducts a statistical analysis of the data set. Both summary and screening criteria table are generated based on cleaned data containing reservoir porosity, permeability, oil API gravity, oil viscosity, reservoir temperature, depth, oil saturation, and net pay thickness. For most characteristics, sandstone reservoirs and carbonate reservoirs are summarized both separately and combined. Four standard statistics including the minimum, maximum, median, and mean values are used to describe the criteria.

Table 5.1. CO<sub>2</sub> miscible flooding properties summary

	Minimum	Maximum	Median	Mean
Porosity (%)	4	29.5	12	14.25
Permeability(mD)	2	700	14	44.35
Gravity(° API)	27	45	38	37
Viscosity (cp)	0.4	6	1.8	1.3
Temperature (°F)	83	260	108.5	133.9
Depth (ft)	1150	11950	5500	6107.3
Oil saturation (%PV)	26.3	89	46	49.6
Net thickness(ft)	15	268	90	110
MMP (psia)	1020	3452	1987.5	2058.4



The two tables below represent CO<sub>2</sub> flooding criteria summarized by previous researcher and this work. Previous researchers include Taber (2004), Aladasani (2010), and Gao and Pan (2010). Different parameters were taken into consideration in these summaries. Screening criteria generated by this research is based on comprehensive consideration including previous criteria, general threshold level, and dataset range standard statistics.

Table 5.2. CO<sub>2</sub> miscible flooding screening criteria summary

	Taber (2004)	Aladasani (2010)	Gao and Pan (2010)	This work	
				Sandstone	Carbonate
Porosity (%)		3-37	>12	7-295	4-23.7
Permeability (mD)			>10	>10	>2
Gravity ( °API)	>22	28-45	>27	>27	>28
Viscosity (cp)	<10	0-35	<10	<3	<6
Temperature (° F)		82-250		83-260	86-232
Depth (ft)		1,500-13,365	>2,500	1,150- 11,950	3,000-11,100
Oil Saturation (%PV)	>20	15-89		>20	
Water Flooding Recovery Factor			20% - 50% OOIP		
Net Thickness (ft)				15-268 (75-137)	

Table 5.3. CO<sub>2</sub> flooding criteria by Taber (2004)

Oil gravity, °API	Depth must be greater than (ft)
> 40	2,500
32 – 39.9	2,800
28 – 31.9	3,300
22 – 27.9	4,000
< 22	Fails miscible, screen for immiscible

At < 1,800 ft, all reservoirs fail screening criteria for either miscible or immiscible flooding with supercritical CO<sub>2</sub>.

## 5.2. CONCLUSION

This study summarized CO<sub>2</sub> miscible flooding field application information and conducted further dataset analysis. Numerical analysis results represent the current U.S. CO<sub>2</sub> miscible flooding reservoir candidate properties and demonstrated existing screening criteria. Although the choice of EOR method is never a result of simple factors, the summarized recommended range can still serve as a reference to benefit field engineers and researchers in the future.

The recommended CO<sub>2</sub> miscible flooding reservoir and fluid properties can be summarized as follows: for sandstone reservoirs: porosity > 7%, permeability > 10 mD, gravity: > 27 °API, viscosity < 3 cp, temperature < 260 °F, and depth > 1,150 ft. For carbonate reservoirs: porosity > 4%, permeability > 2 mD, gravity: > 28 °API, viscosity < 6 cp, temperature < 232 °F, and depth > 3,000 ft. The oil saturation at the beginning of

the CO<sub>2</sub> flood should be more than 20% pore volume and the favorable net pay thickness is from 75 to 137 ft.

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